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BACKGROUND INFORMATION DOCUMENT FOR THE DEVELOPMENT OF REGULATIONS TO CONTROL THE BURNING OF HAZARDOUS WASTES IN BOILERS AND INDUSTRIAL FURNACES - VOLUME I, INDUSTRIAL BOILERS

Engineering-Science
Fairfax, VA

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VOLUME I
INDUSTRIAL BOILERS

Submitted to

U.S. Environmental Protection Agency
Office of Solid Waste
401 M Street, S.W.
Washington, D.C. 20460

January 1987
FA035/50A-E

Submitted by

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ENGINEERING-SCIENCE

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SECTION 1

SUMMARY AND CONCLUSIONS

The initial hazardous waste management facility standards promulgated on May 19, 1980 under the Resource Conservation and Recovery Act (RCRA), controlled the burning of hazardous waste in incinerators but exempted the burning of hazardous waste for the purpose of energy recovery. This exemption for boilers and other combustion devices was allowed by EPA because the Agency had not investigated the extent of the practice, the risks that may be posed to human health, the environment, or regulatory alternatives.

Since the promulgation of the incinerator rule, EPA has undertaken a research program to obtain the information needed to develop and evaluate alternatives for regulating the burning of hazardous waste in boilers and industrial furnaces. The results of this research are presented in this document and two companion volumes, which together comprises the Background Information Document (BID) for use by EPA in its Regulatory Impact Analysis (RIA) of the practice of burning hazardous waste in industrial boilers and industrial furnaces. This volume contains background information on industrial boilers as related to hazardous waste burning. The practice of burning hazardous waste in industrial furnaces is addressed in Volume II. An assessment of the risk associated with burning hazardous waste in industrial boilers and furnaces is made in Volume III of the BID.

One of the major tasks of EPA's regulatory development efforts was to characterize industrial boilers in terms of parameters believed to affect their hazardous waste burning potential and/or which impact the selection of regulatory alternatives. This was done to provide an understanding of industrial boilers needed to develop practical regulatory approaches. The boilers were characterized in terms of their design, fuel usage, air emissions, and control techniques as well as their population distribution.

Another major task completed by EPA in its regulatory development efforts was to determine the hazardous waste incineration performance capability of boilers. EPA conducted field testing on a total of 15 industrial boilers. The test program was designed to: (1) determine if boilers operated under steady-state conditions to achieve maximum combustion efficiency could achieve 99.99% destruction and removal efficiency (DRE) of principal organic hazardous constituents (POHCs) in the waste; and (2) determine how changes in operating conditions (e.g., waste firing rates, boiler load, excess flue gas oxygen levels) would affect the boiler's ability to achieve 99.99% DRE of POHCs -- so-called parametric testing. The boilers tested ranged in size from a small 8 million Btu/hr fire-tube boiler to a 250 million Btu/hr water-tube boiler. The hazardous waste burned ranged from toluene and methanol wastes with a heating value of 18,500 Btu/lb (similar to heating value of No. 6 fuel oil) to a methyl acetate waste with a heating value of less than half that of No. 6 fuel oil. Both these fuels were spiked with chlorinated organics for test purposes. Auxiliary fuels burned included natural gas, No. 6 fuel oil, coal, and waste wood.

In total, over 100 individual stack tests were conducted. The results indicated that the 99.99% destruction and removal efficiency (DRE) standard for the tested POHCs is achievable. These POHCs included some of the more difficult compounds to destroy such as carbon tetrachloride, chlorobenzene, trichloroethylene, and tetrachloroethylene. The 99.99% DRE of POHCs was found to be achievable under various operating conditions including load changes, waste feed rate changes, and excess air rate changes for boilers co-firing hazardous waste fuels with fossil fuels. There appears to be no direct correlation between combustion efficiency (as evidenced by smoke emissions) and POHCs destruction. Boilers operated under poor combustion efficiency still achieved 99.99% DRE of POHCs. When the boilers were operated at maximum combustion efficiencies, the DREs exceeded 99.99%.

These results should not be interpreted to indicate that any boiler burning any hazardous waste will achieve 99.99% DRE. Not all parameters could be tested at the boilers where the operating conditions were varied. For example, the maximum waste firing rate tested was 56% of the total heat input, and the boilers were not operating at loads below 25%, the heating values of the wastes were all greater than 11,000 Btu/lb, and excess oxygen levels did not exceed 10%. Therefore, we do not fully know how narrow the envelope of operating conditions may be to ensure both peak combustion efficiency and 99.99% DRE for a boiler operating at the extremes of "steady state" operation.

Typical chlorinated products of incomplete combustion (PICs) found during the boiler testing included chloroform, trichloroethane, tetrachloroethylene, dichloromethane, chloromethane, and carbon tetrachloride. Two non-chlorinated PICs always found were benzene and toluene. The measured chlorinated PIC emissions were generally of the same order of magnitude as measured during the conventional fuel firing. They were also generally of the same order of magnitude as the POHC emissions. Exceptions to these generalizations occurred during sootblowing and waste atomizer upset portions of the parametric testing.

Several potential problems should be noted related to the testing program. There is a substantial degree of uncertainty when trying to quantify emissions of unburned organics. The test results may have over- or underestimated the unburned organic emissions attributed to the burning of hazardous wastes. The potential for overestimating these emissions exists because the hazardous waste was co-fired with fossil fuels. The burning of fossil fuels produces similar PICs as the burning of hazardous wastes. Some organics found in the test samples could have been the result of contamination of the sampling train absorbent or the use of laboratory solvents. It is also possible that the PIC emissions could have been underestimated, since only Appendix VIII of the Code of Federal Regulations pollutant PICs were identified (there are in fact more PICs than the 100 pollutants the GC/MS was used to quantify). Even though additional research is needed in order to fully understand the combustion reactions, the available data suggests that health risks (presented in Volume 3) posed by PIC emissions are probably not significant when a DRE of 99.99% of POHCs is achieved and the combustion efficiency is good.

Several surveys were completed by EPA and other organizations to help quantify and characterize the hazardous waste being generated and that which may be burned in industrial boilers. A review of these surveys indicate that approximately 264 metric tons of hazardous wastes regulated by RCRA were generated in 1981. Total burnable hazardous waste is estimated at 160 million metric tons per year. Of this total, it is estimated that less than 4 million metric tons were burned in industrial boilers in 1982.

Cost elements needed for an economic impact analysis of regulatory alternatives were developed. Capital and operating and maintenance costs were provided for retrofitting industrial boilers for burning hazardous waste. This BID includes cost elements for:

- Equipment to pretreat the waste by blending, straining, and thermal treatment for viscosity adjustment.
- New or modified burner guns to fire the waste.
- Equipment for combustion controls.
- Equipment for monitoring waste feed rates, oxygen, and carbon monoxide levels.
- Equipment for controlling particulate and gaseous stack emissions.

In addition to these cost elements, fuel costs were compiled and projected through 2010 for natural gas, residual fuel oil, distillate fuel oil, and coal for the ten EPA regions of the country.

SECTION 2

INTRODUCTION

The Resource Conservation and Recovery Act (RCRA) requires EPA to develop regulations for the storage, handling, and disposal of hazardous wastes. It also requires that EPA encourage in its regulations the recycling of wastes. On May 19, 1980, EPA issued requirements for hazardous waste incinerators. At that time, the burning of hazardous wastes in boilers was not regulated because EPA lacked sufficient information to determine the extent of the risk to public health posed by such burning, as well as the extent of regulatory controls that would be necessary to address the risks. Since 1980, EPA has researched the nature and extent of the practice of burning hazardous waste as fuel in boilers. A boiler is defined in 40 CFR 260.10 as an enclosed device using controlled flame combustion with specified design and operating characteristics related to the recovery of energy. This document presents the results of research efforts for industrial boilers.

OBJECTIVE

The objective of this project was to provide sufficient research and investigation into the concept and practice of burning hazardous wastes in industrial boilers such that EPA could develop and evaluate regulatory alternatives. The information and data collected by this investigation constitutes a Background Information Document (BID) for use by EPA in preparing its Regulatory Impact Analysis (RIA).

The investigation undertaken by EPA to obtain the information needed for its regulatory development effort covering hazardous waste burning in industrial boilers entailed the following tasks:

- Establishing an understanding of boilers by characterizing them in terms of those parameters thought to influence regulatory decisions.
- Field testing a variety of industrial boilers to establish their capacity for destroying hazardous waste.
- Assessing the risk to human health and the environment associated with burning hazardous waste in industrial boilers.
- Defining the extent of the practice of burning hazardous waste in industrial boilers.
- Compiling the cost of items to be included in an economic impact analysis of regulatory options.

These tasks were completed by a number of EPA groups and their contractors. A summary of the results of the field testing and hazardous waste practice surveys are documented in this volume of the BID. More detailed descriptions of these efforts may be found in the reports referenced throughout this document. A summary of risk assessment results are presented in Volume 3 of this BID. The other task results are presented along with the summaries of the test program and waste usage surveys in the following sections of this document. The information is organized as described in the following paragraphs.

Section 3 characterizes industrial boilers in terms of their design, fuel usage, population, air pollution emissions, and control techniques. This characterization is made to provide a basic understanding of boilers needed to develop a practical regulatory approach.

Section 4 describes the results of tests conducted in order to measure the performance of industrial boilers in burning hazardous wastes. This performance is described in terms of achieved DRE of POHCs, and the emissions of PICs, particulate matter, HCl, metals, and combustion gases.

Section 5 characterizes the various waste streams used as supplementary fuel in industrial boilers.

Presented in Section 6 are cost data needed by EPA to conduct an Economic Impact Analysis (EIA) of regulatory alternatives. Costs are presented for those items used in analyzing the economic impact in terms of how the fuel and waste disposal savings of hazardous waste burners are altered by the various regulatory alternatives. The items being provided in this document fall into three major categories: (1) conventional fuel prices, (2) costs to modify the boiler system to fire the waste, and (3) the major operating and maintenance costs associated with burning hazardous waste.

SECTION 3

CHARACTERIZATION OF INDUSTRIAL BOILERS FOR BURNING HAZARDOUS WASTES

An essential element for defining the impact of regulating the disposal of hazardous wastes in industrial boilers is a characterization of the boilers for this use. Not all types of boilers are suitable for burning every type of waste, e.g., gas-fired and oil-fired units are not suited for burning solid hazardous waste materials. An understanding of the different boiler types is therefore necessary to develop a practical regulatory approach. Also, since the regulatory impact will depend on the number of boilers capable of burning hazardous waste, it is necessary to describe the boiler population and how this population is distributed by size, type, fuel, and capacity. Finally, the current and future extents of the practice of burning hazardous waste in boilers must be estimated. This section presents the existing boiler population, the estimated air emissions, and the types of air pollution control devices presently used to abate these emissions. Estimates of the quantity of hazardous waste burned in these boilers are discussed in Section 5 of this document.

DESCRIPTION OF EXISTING BOILER POPULATION

Industrial boilers are generally described in terms of the heat transfer configuration and the fuel burned. The first term defines the physical structure of the boiler while the latter indicates the fuel type and firing mechanism.

Heat Transfer Configurations

There are three basic types of heat transfer configurations: water-tube, fire-tube, and sectional which are also referred to as "cast iron" from the material of construction used. A brief description of these three types follows.

Water-tube boilers are designed to transfer heat from the combustion gases flowing over the outside of the tubes to water, steam, or other fluid contained inside the tubes. Because the tubes in these units are of relative small diameter, they provide rapid heat transfer. They are available in many sizes, generally in the range of 15×10^6 to 1500×10^6 Btu/hr. All boilers greater than 50×10^6 Btu/hr are of this type. These boilers generate high-pressure, high-temperature steam up to 12,000 KPA (1740 psig) and 810°K (1000°F) (Reference 1).

In fire-tube boilers, the hot combustion gases flow through the inside of tubes with water, steam, or other fluid contained outside the tubes. Fire-tube units are not available in capacities as large as water-tube units with most less than 20 x 10^6 Btu/hr (Reference 1). They constitute the largest share of small and medium-size industrial boilers. Because they are susceptible to structural failure when subject to large variations in steam demand, they are generally used where loads are relatively constant.

Sectional or cast iron boilers employ irregularly shaped heat exchangers and hence cannot be classed as either water-tube or fire-tube. Hot combustion gases are directed through some of these passages, transferring heat through metal walls to water or steam in other passages. These units are manufactured in identical sections which can be joined together according to the needs of the operator. Cast iron boilers are the smallest of the three boiler types, with a maximum size of only 10 x 10^6 Btu/hr thermal input (Reference 2). They are generally used for producing low pressure steam or hot water for commercial or institutional establishments. Generally, cast iron units cost more than firetube units for comparable size, but require less maintenance and can handle overloading in demand surges.

Fuel Usage

Boilers are also described by the type of fuel they are designed to burn. The vast majority of industrial boilers are designed to burn one or more of the fossil fuels: gas, oil, or coal. Nuclear powered boilers are currently used only by the utility industry and military. They are inherently unsuitable for hazardous waste disposal. Wood, bagasse, municipal solid waste, industrial solid waste, and refuse derived fuel are also used as fuels but comprise less than 1% of the boiler population and less than 0.01% of the heat input capacity. Because they comprise the bulk of the boilers capable of burning hazardous waste, this analysis will focus on gasfired, oil-fired, and coal-fired types.

Oil-fired boilers are often distinquished by the type of oil used, i.e., whether they use distillate or residual oil.

Coal-fired boilers are further categorized by firing mechanisms which can be divided into three major groups: stokers firing, suspension firing, and fluidized bed combustion. A stoker is a conveying system that feeds coal into a furnace while providing a moving grate upon which the coal is burned. In suspension firing the fuel is blown into the boiler and burned as a suspension of particles in combustion air. Fluidized bed combustion boilers burn the coal on a bed of inert particles through which air is blown so that the bed behaves as a fluid. There are very few of these units in use as this is an emerging technology.

Stoker firing systems can be further divided into three groups: underfeed stoker, overfeed stoker, and spreader stoker. In an underfeed stoker, coal is fed to the bottom of a fuel bed, where moisture and volatiles are driven off and the coal is coked. The volatiles rise through the bed and undergo combustion above the bed. The coked coal is forced to the top of the bed by newly fed coal and spills out of the bed onto side gates, where combustion is completed. Combustion air is supplied at the side grates; also overfire air is often supplied to the flame zone above the bed. In an overfeed stoker, coal is fed onto a continuous conveyer called a traveling grate. The grate carries the coal under an adjustable gate and through the furnace chamber, where combustion air is fed through the bottom of the grate. The coal burns as it moves across the furnace. In a spreader stoker, feeders distribute coal uniformly over the grate. Combustion air is provided both over and under the grate.

Suspension firing systems include pulverized coal-fired and cyclone systems. In pulverized coal-fired units the coal is pulverized to the consistency of fine powder and pneumatically injected through the burners into the furnace. Combustion begins at the burners and continues into the furnace volume. Cyclone units are used to burn low fusion temperature coal that has been crushed to a maximum particle size of about 4 mesh. The coal is fed tangentially, with primary air to a horizontal cylindrical chamber. In the furnace, the smaller coal particles are burned in suspension, while, because of the tangential firing method, the larger particles are forced against the outer wall of the chamber. Ash is also forced against the outer wall, where, because of its low fusion temperature, it forms a molten layer of slag and causes larger coal particles to adhere to the combustion chamber wall until they are burned instead of becoming entrained in exhaust gases leaving the combustion chamber.

Boiler Population

Table 3.1 summarizes the installed population of industrial boilers by design type and Figure 3.1 presents their relative distribution by capacity. Although nearly 60% of the boilers are cast iron units, these units account for only 6% of the installed capacity. Water-tube boilers, on the other hand, represent 7% of the boilers by number, but account for 70% of the installed capacity. As shown by Figure 3.1, water-tube boilers are available over a larger size range than the other types. Figure 3.1 also shows that the largest concentration of boiler capacity is in the 10 to 50 x 10^6 Btu/hr range, which contains 26% of the installed capacity. Units over 250 x 10^6 Btu/hr thermal input are the next largest group accounting for 20% of the installed capacity.

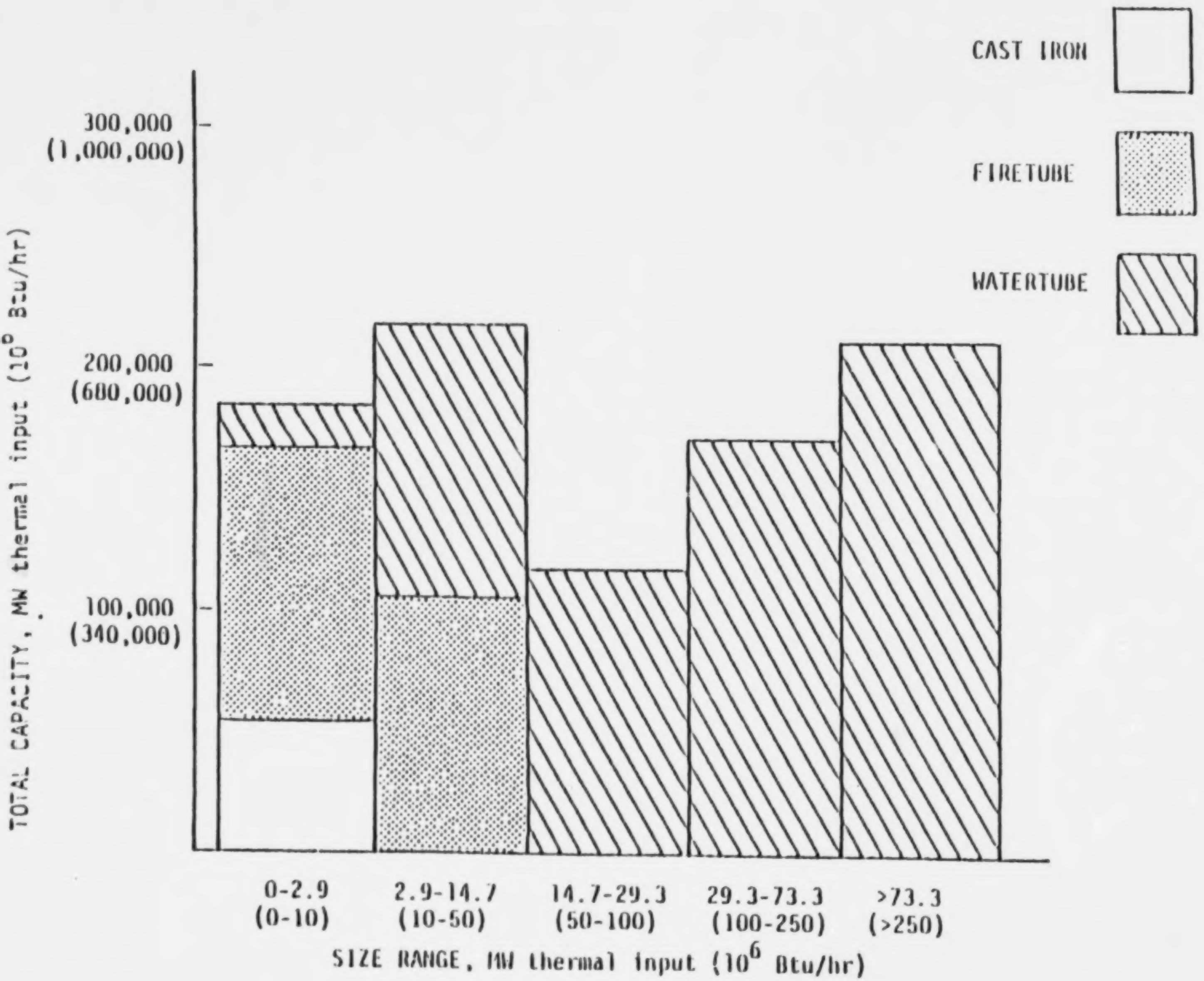
The distributions of the three types of boilers by capacity and fuel are summarized in Tables 3.2 through 3.4. As shown in Table 3.2 about 25% of the installed water-tube boiler capacity is coal-fired, 32% is oil-fired, and 43% is natural gas-fired. This distribution varies with size. In the smallest size range (less than 10 x 10^6 Btu/hr thermal input), only 7% of the capacity is coal-fired, whereas in the largest boiler size group (above 250 x 10^6 Btu/hr thermal input), 30% of the installed capacity is coal-fired. Even in this large size group, however, 47% of the currently installed water-tube capacity is gas-fired. In comparison, only 6% of the installed fire-tube capacity is coal-fired, 43% is oil-fired, and 51% is natural gas-fired as shown in Table 3.3. These units range in size up to 50 x 10^6 Btu/hr thermal input. For cast iron boilers, 12% of the installed capacity is coal-fired, 33% is oil-fired, and 55% is natural gas-fired, as shown in Table 3.4. Cast iron boilers are the smallest of the three types, with a maximum size of only 10 x 10^6 Btu/hr thermal input.

TABLE 3.1

BOILER POPULATION DISTRIBUTION BY HEAT - TRANSFER CONFIGURATION

Heat-Transfer Configuration	Boiler Population		Total Boiler Capacity	
	Number of Boilers	Percent of Total	MW Thermal Input (10^6 Btu/hr)	Percent of Total
Water-Tube	37,696	7.5	638,665 (2.2×10^6)	70.0
Fire-Tube	173,936	34.3	219,360 (0.76×10^6)	24.2
Cast Iron	295,298	58.2	52,570 (0.18×10^6)	5.8

FIGURE 3.1



RELATIVE DISTRIBUTION BY CAPACITY OF THE THREE TYPES OF INDUSTRIAL BOILERS[1]

TABLE 3.2

DISTRIBUTION OF U.S. WATER-TUBE INDUSTRIAL BOILERS BY UNIT SIZE AND FUEL TYPE
(MW Thermal Input (10^6 Btu/hr))

Fuel	Capacity by Unit Size 0 to 2.9 (0 to 10)	2.9 to 14.7 (10 to 50)	14.7 to 29.3 (50 to 100)	29.3 to 73.3 (100 to 250)	>73.3 (>250)	Totals
Pulverized Coal						
Number of Units	0	0	0	453	266	719
Total Capacity, MW	0	0	0	19,895	40,180	60,075
Thermal (10^6 Btu/hr)	(0)	(0)	(0)	(67,800)	(137,000)	(204,800)
Spreader-Stoker Coal						
Number of Units	46	464	285	474	88	1,357
Total Capacity, MW	70	4,650	6,175	20,295	11,010	42,200
Thermal (10^6 Btu/hr)	(240)	(15,900)	(21,060)	(69,000)	(37,600)	(143,800)
Underfeed-Stoker Coal						
Number of Units	578	1,500	788	169	41	3,076
Total Capacity, MW	680	14,105	17,265	7,080	5,230	44,360
Thermal (10^6 Btu/hr)	(2,300)	(48,000)	(58,900)	(24,200)	(17,800)	(151,200)
Overfeed-Stoker Coal						
Number of Units	59	345	207	85	28	724
Total Capacity, MW	85	3,470	4,455	3,555	3,510	15,075
Thermal (10^6 Btu/hr)	(290)	(11,800)	(15,200)	(12,100)	(12,000)	(51,390)
Residual Oil						
Number of Units	3,217	5,637	1,654	1,039	325	11,872
Total Capacity, MW	3,960	48,190	35,640	44,790	43,570	176,150
Thermal (10^6 Btu/hr)	(13,500)	(164,000)	(122,000)	(153,000)	(148,600)	(601,100)
Distillate Oil						
Number of Units	3,151	1,067	191	170	30	4,609
Total Capacity, MW	2,560	8,280	4,295	6,370	4,085	25,590
Thermal (10^6 Btu/hr)	(8,700)	(28,200)	(14,600)	(21,700)	(13,900)	(87,100)
Natural Gas						
Number of Units	4,414	6,533	2,515	1,443	434	15,339
Total Capacity, MW	4,475	57,900	53,585	63,320	95,935	275,215
Thermal (10^6 Btu/hr)	(15,300)	(197,500)	(182,800)	(216,000)	(327,200)	(938,800)
Total All Fuels						
Number of Units	11,465	15,546	5,640	3,833	1,212	37,696
Total Capacity, MW	11,830	136,595	121,415	165,305	203,520	638,665
Thermal (10^6 Btu/hr)	(40,330)	(465,400)	(414,560)	(563,800)	(694,100)	(2,178,190)

TABLE 3.3

DISTRIBUTION OF INDUSTRIAL FIRE-TUBE BOILERS BY SIZE AND FUEL TYPE

(MW Thermal Input (10^6 Btu/hr))

	Capacity by Unit Size		
Fuel	0 to 2.9 (0 to 10)	2.9 to 14.7 (10 to 50)	Total
Coal			
Number of Units	8,112	1,224	9,336
Total Capacity, MW	5,650	7,780	13,430
Thermal (10^6 Btu/hr)	(19,270)	(26,530)	(45,800)
Residual Oil			
Number of Units	46,884	4,353	51,237
Total Capacity, MW	35,280	25,860	61,140
Thermal (10^6 Btu/hr)	(120,330)	(88,200)	(208,530)
Distillate Oil			
Number of Units	22,643	2,653	25,296
Total Capacity, MW	17,770	15,770	33,540
Thermal (10^6 Btu/hr)	(60,610)	(53,790)	(114,400)
Natural Gas			
Number of Units	79,456	8,611	88,067
Total Capacity, MW	59,120	52,130	111,250
Thermal (10^6 Btu/hr)	(201,630)	(177,790)	(379,420)
Total			
Number of Units	157,095	16,841	173,936
Total Capacity, MW	117,820	101,540	219,360
Thermal (10^6 Btu/hr)	(401,840)	(346,310)	(748,150)

TABLE 3.4

DISTRIBUTION OF INDUSTRIAL CAST IRON BOILERS BY FUEL TYPE (MW Thermal Input (10^6 Btu/hr))

Fuel	Boiler Capacity[a]
Coal	
Number of Units	35,965
Total Capacity, MW	6,330
Thermal (10^6 Btu/hr)	(21,590)
Residual Oil	
Number of Units	59,894
Total Capacity, MW	10,780
Thermal (10^6 Btu/hr)	(36,770)
Distillate Oil	
Number of Units	37,612
Total Capacity, MW	6,740
Thermal (10^6 Btu/hr)	(22,990)
Natural Gas	
Number of Units	161,827
Total Capacity, MW	28,720
Thermal (10^6 Btu/hr)	(97,950)
Total All Fuels	
Number of Units	295,298
Total Capacity, MW	52,570
Thermal (10^6 Btu/hr)	(179,400)

[a] All cast iron boilers have a capacity less than 4.0 MW thermal input (14 x 10^6 Btu/hr).

EXISTING EMISSIONS FROM INDUSTRIAL BOILERS

Criteria Pollutants

The estimated (by Kemp and Dykema (Reference 3) and Devitt, et al. (Reference 1)) emissions of criteria pollutants from industrial boilers are summarized in Table 3.5 (Reference 2). There is no information indicating that control devices or techniques for criteria pollutants other than particles have been adopted to a significant degree in the industrial boiler industry. The estimated net control of particle emissions, presented in the next subsection have been applied to the uncontrolled emission rate to yield the estimated existing emission rate of particles.

None of the test data, accumulated during test burns of industrial boilers co-firing hazardous wastes (collected in conjunction with development of this background information document) indicate that the rates of emission of carbon monoxide or hydrocarbon are affected by co-firing of hazardous waste. The rates of particles, sulfur dioxide, and nitrogen oxides emissions will be affected only insofar as the waste stream contains ash, or sulfur or nitrogen compounds.

Metals Emissions

Trace elements are found in fossil fuels. The largest amounts are found in coals and residual oil. No data were found on the trace element concentrations in either gas or distillate oil. Nor were any emissions factors for trace elements from gas or oil-fired combustion equipment found. The concentration of trace metals in distillate oils is generally believed to be quite low; the concentration in gas fuels is thought to be nearly zero. Table 3.6 (Reference 4) lists some toxic metals and their approximate, uncontrolled rates of emission from oil- and coal-fired boilers. The emission rate of a trace metal depends upon:

- Its concentration in the fuel
- The vapor pressure of the element and its products of combustion
- The combustion zone temperature
- The temperature history of the combustion gases in the boiler

It is not necessary that the flame temperature exceed the boiling point of an element for it to evaporate, the temperature must only be high enough to create a significant vapor pressure. There is a correspondence between enrichment of metals in small particles and their occurrence as mineral sulfides in the earth's crust. This implies that ease of reduction to base metals (which are usually, but not always, more volatile than metal oxides) or metal hydrides during the initial phases of combustion of a fuel particle may facilitate evaporation of the metals (Reference 6). The more volatile elements (and those that form volatile oxides) appear to partition favorably into the fly ash. The less volatile elements partition evenly between the fly ash and slag. Apparently, the more volatile elements become vaporized in the high temperature flame and condense into very small particles (fumes) as the flame temperature is quenched by radiant and convective cooling. The distribution of particle sizes and the elements affected depend on both the maximum flame temperature and the rate of cooling.

TABLE 3.5

SUMMARY OF EXISTING EMISSIONS OF CRITERIA POLLUTANTS FROM INDUSTRIAL BOILERS

(Reference 3)

		Emission Factor (lb/10^6 Btu)				
		Particles	NO_x	SO_2	CO	HC
Gas-Fired Boilers	Uncontrolled	0.005 to 0.015	0.067 to 0.442[c]	0.001	0.017	0.003
	Net Control	0	0	0	0	0
	Controlled	0.005 to 0.015	0.067 to 0.442	0.001	0.017	0.003
Distillate Oil-Fired Boilers	Uncontrolled	0.015	0.102 to 0.249[c]	1.040S[a]	0.037	0.007
	Net Control	0	0	0	0	0
	Controlled	0.015	0.102 to 0.249	1.040S	0.037	0.007
Residual Oil-Fired Boilers	Uncontrolled	(0.068S[a] + 0.020)	0.156 to 0.842[c]	1.060S[a]	0.034	0.007
	Net Control	0	0	0	0	0
	Controlled	(0.068S + 0.020)	0.156 to 0.842	1.060S[a]	0.034	0.007
Pulverized Bituminous Coal-Fired Boilers (Dry Bottom)	Uncontrolled	0.679A[b]	0.637	1.612S[a]	0.042	0.013
	Net Control	81%	0	0	0	0
	Controlled	0.129A[b]	0.637	1.612S[a]	0.042	0.013
Bituminous Coal-Fired Spreader Stoker Boilers	Uncontrolled	0.551A[b]	0.637	1.612S[a]	0.085	0.042
	Net Control	75%	0	0	0	0
	Controlled	0.138A[b]	0.637	1.612S[a]	0.085	0.042

[a] S is the fuel sulfur content.

[b] A is the fuel ash content.

[c] NO_x emissions are strongly dependent on firing type.

TABLE 3.6

EMISSION FACTORS (UNCONTROLLED) OF SELECTED TOXIC TRACE ELEMENTS FROM INDUSTRIAL BOILERS

(Reference 4)

	Emission Factor (lb/10^6 Btu)		
Element	Residual Oil-Fired Boilers	Spreader Stoker Bituminous Coal-Fired Boilers	Pulverized Bituminous Coal-Fired Boilers
Antimony	0.000023	0.00047	0.00035
Arsenic	0.000042	0.00279	0.00214
Barium	0.000067	0.00744	0.00977
Beryllium	0.000005	0.00018	0.00023
Cadmium	0.000121	0.00014	0.00019
Chromium	0.000070	0.00465	0.00605
Cobalt	0.000119	0.00072	0.00093
Lead	--------	0.00161	0.00209
Mercury	0.000002	0.00002	0.00002
Selenium	0.000037	0.00054	0.00070
Thorium	<0.000002	0.00012	0.00014

Health risk considerations imply that the most critical emissions from boilers co-firing hazardous wastes will be toxic metals. Cowherd, et al., in the course of an investigation of the hazardous emissions from coal-fired utility boilers, ranked various trace element constituents of coal according to their reported toxicities (Reference 5). They then sampled a boiler exhaust gas with cascade impacters and analyzed the individual stages for the various elements. Table 3.7 lists the mass fraction of the total amount of the eight most toxic metals that was found to be in the particles of less than 0.87 micrometers diameter. They did not report enrichment for Hg, Se, and As. Lyon, following similar tests, classified elements according to their propensity to be incorporated into the boiler slag (Class 1); be concentrated in the fly ash and exhausted from the electrostatic precipitator (Class 2); or remain completely in the gas phase (Class 3) (Reference 6), see Table 3.7.

Where the measurements of these two investigations overlap the conclusions agree except for thallium. There appears to be an enrichment of the most toxic metal elements in the smallest particles emitted during coal combustion. These small particles are difficult to remove; mechanical collectors and scrubbers are relatively ineffective. Only 15% of industrial coal-fired boilers (3% of all industrial boilers) are presently equipped with either electrostatic precipitators or fabric filters, which are needed to control small particle emissions.

CURRENTLY INSTALLED EMISSION CONTROLS

Data gathered from the National Emissions Data System (NEDS) reveal that uncontrolled oil- and gas-fired industrial boilers generally comply with emissions regulations encoded in State Implementation Plans (Reference 1,7). Therefore, there are few air pollution control devices installed on boilers that burn either of these fuels. Approximately two-thirds of coal-fired industrial boilers have some particle control device installed. Sulfur dioxide emissions are generally not controlled. A survey of 2,533 boilers (Reference 8), summarized in Table 3.8, revealed that cyclones are the most commonly installed control devices.

Table 3.9 summarizes the percent collection efficiency and percent application of control devices by boiler firing type. By combining these data with those in Table 3.2 it can be estimated that approximately 70% of the installed capacity of coal-fired industrial boilers is equipped with some type of particle control device. However, coal-fired equipment comprises only about one-fourth of the total installed capacity, so only about 17% of the installed industrial boiler capacity has any type of control device.

Control Techniques for Particulate Matter

The four types of particle emission control devices that are presently in use to any significant extent are electrostatic precipitators, fabric filters, wet scrubbers, and mechanical collectors (cyclones). The presently installed equipment is in place exclusively for the purpose of attaining compliance with standards for emission of particles. These four devices are discussed in this section. Other, advanced design equipment is in use or undergoing evaluation. The more promising of these devices are discussed in the next section.

TABLE 3.7

ENRICHMENT OF TOXIC ELEMENTS IN SMALL PARTICLES

Element	% of Element in Particles Less Than 0.87 Microns Diameter (Ref. 5)	% of Element in Particles Greater Than 0.87 Microns Diameter (Ref. 5)	Element Class[a] (Lyon, Ref. 6)
Be	82	18	--
Cd	59	41	2
Pb	32	68	2
Hg	--	--	3
Se	--	--	2 or 3
Te	72	28	--
Th	84	16	1
As	--	--	2
Cr	--	--	1 or 2

[a] Class 1 elements partition evenly between boiler slag and fly ash.
Class 2 elements concentrate in small particles.
Class 3 elements remain in vapor phase through ESP.

TABLE 3.8

INSTALLED AIR POLLUTION CONTROL DEVICES COAL-FIRED BOILER

(Reference 8)

Control Device	Percent by Number
None	33
Cyclone	47
Scrubber	4
Electrostatic Precipitator	14
Fabric Filter	1

TABLE 3.9

ESTIMATED APPLICATION OF CONTROL EQUIPMENT TO COAL-FIRED INDUSTRIAL BOILERS, 1978

System Type	Average Collector Efficiency (%)	Control Application (%)	Net Control (%)
Pulverized	85	95	81
Cyclone	82	91	75
Stoker	85	62	53

Source: Reference 1 and 2.

Electrostatic Precipitators

Process Description. Electrostatic precipitators (ESPs) remove particles from a gas stream by impressing an electrostatic charge upon them and then causing them to migrate to oppositely charged collection plates in a high potential d.c. field. In addition, gravitational settling can account for significant fractional removal of large diameter (>40 u) particles. Incoming, particle laden gas flows by a discharge electrode, which, because its electromotive potential is high relative to ground, is surrounded by an electrostatic corona. As particles flow through the corona they accumulate charged ions and thereby become charged. Thus charged, the particles migrate toward the collection electrodes (or plates) whose potential is at ground, where they are collected. Removal of the particles from the collection electrode is effected by rapping (vibrating) the electrode.

Rapping the collection electrodes may be done by pneumatic or electric vibrators or by mechanical dropping hammers. Reentrainment of particles, released from the collection electrode during rapping, is a significant cause of inefficiency, whatever the rapper design. Precipitators normally consist of 2 to 4 parallel sections, each consisting of 2 to 4 sequential fields. Thus, if rapping cycles are well conceived, reentrainment from only the final field is problematical.

Air flow inside the precipitator must be evenly distributed to avoid overloading some portions while underloading others. Velocities are kept low (4 to 8 ft/sec) to avoid scouring collected particles from the collection electrode.

Applicability to Industrial Boilers. The first successful application of an electrostatic precipitator was in 1907, when Cottrell installed a unit to collect acid mist from a sulfuric acid plant. Since then, many thousands of units have been installed. ESPs are available in sizes to handle from 5000 acfm (0.5×10^6 Btu/hr boiler) to the largest electric utility boilers. Electrostatic precipitation is a well established technology that has been studied and researched for nearly 80 years. Adequate solutions have been developed for most technical problems so that ESPs are applicable to nearly any boiler fly ash control situation. The largest power utility boiler can be equipped within 2 to 4 years, smaller boilers even more quickly.

Factors Affecting Performance. The boiler operating parameter that has the greatest effect on the performance of an ESP is the resistivity of the ash particles. If the resistivity is too high (greater than 10^{11} ohm-cm) the charges on individual particles will flow through the dust layer at a rate slower than the rate of particle (and charge) accumulation. Ultimately an electric breakdown will occur in the dust layer that will initiate excessive sparking between the precipitation electrodes (Reference 9). Sparking wastes charges and thereby attenuates performance. At higher resistivity ($>10^{12}$ ohm-cm) back corona effects will introduce positive ions into the electrode interstices and reduce the charges on the particles. If the ash resistivity is too low ($<10^7$ ohm-cm) particles will loose their charges immediately upon contact with the collection electrode. Then, lacking electrostatic adhesive, they will be easily reentrained.

Ash resistivity is more problematical for ESPs in service on coal-fired industrial boilers than those in service on electric utility boilers because, unlike utilities, industrial users do not normally purchase long-term coal commitments. As a result industrial boilers burn a more variable fuel, having a more variable ash resistivity. Ash with acceptable resistivity results from combustion of coal with high alkali (Na_2O and Li_2O), Fe_2O_3 content and low concentrations of Ca, Mg, Si, and P oxides. Resistivity drops as sulfur content increases. Injections of SO_3 (and some proprietary compounds) appears to be an effective means of reducing excessive ash resistivity and thereby improving ESP performance.

The size of the ash particles is also, an important variable. ESPs appear to be least efficient for collection of particles in the size range of 0.1 to 1.0 microns diameter (Reference 10). There are indications that penetration through hot side ESPs (those located upstream of the air preheater) are primarily the result of rapping losses of particles greater than 2 microns diameter.

Most oil-fired boilers now employing ESP control were converted from their original coal fuel (Reference 11). The ESP on such a unit, if not modified, may be only 50% efficient. Oil ash tends to have a high carbon content. The carbonaceous nature of the ash causes two types of problems. First, the ash can be sticky and tar-like in nature and therefore difficult to remove from the collection plates, insulators, frame members, and other surfaces. Its accumulation on the collection plates eventually effects sparking which creates a fire hazard. This difficulty can be overcome somewhat by moving the ESP to the upstream side of the air preheater, or by practicing fly ash reinjection. Both techniques yield a dryer, less sticky ash but neither alleviates the second problem - the resistivity of the ash is low because of the high concentration of relatively conductive carbon. Low resistivity ash is subject to reentrainment because it is not electrostatically bound to the collection electrode.

There is no reason why an ESP could not be installed to control the particle emissions from a gas-fired boiler. However, particle emissions from gas-firing are so low that control is unnecessary.

Impact of Burning Hazardous Waste. Corrosion is the major anticipated impact of combustion of hazardous waste in boilers equipped with ESPs. Combustion of S, P, or Cl containing compounds will result in emission of the corresponding inorganic acids. ESPs can be designed to remove particles from highly corrosive gases (the first installation was at a sulfuric acid plant) by incorporating special materials of construction. It is unlikely that this will have been done for an ESP that was originally designed to control particle emissions from a coal-fired boiler.

A second potential impact could be alteration of the ash resistivity by these acids. This could be beneficial or detrimental to the ESP performance, depending upon the resistivity of the coal ash.

ESPs can be expected to efficiently (>99%) remove particles from the boiler flue gas. Their minimum efficiency is for particles of approximately 0.5 microns diameter. However, this minimum efficiency is in excess of 90%. As was mentioned previously, toxic metals appear to be concentrated in small particles; those less than 0.9 microns in diameter. However, even though 10% of the particles most heavily laden with the toxic metals may penetrate the ESP, the net control of the toxic metals will be over 90%.

A dry ESP will not remove any vapor phase substances. These include the hazardous organic compounds, hydrochloric acid and vaporous metals (such as mercury). It would be necessary to cool the exhaust gas to condense or absorb these substances.

Fabric Filtration

Process Description. The microscopic mechanisms by which fabric filters (baghouses) remove particles from gas streams are less understood than those operating in other air pollution control devices (Reference 12). The typical pore size of fabric is on the order of 10 to 100 microns, which is large relative to the diameters of the particles to be removed. When, at the beginning of a gas cleaning cycle, the fabric is clean, the removal mechanisms for large particles appear to be direct interception and impaction. Large particles (>2 microns diameter) are those having sufficient inertia to be separated from gas slip streams as the gas flows around individual fibers. Small particles (those less than 0.1 microns diameter) are not subject to inertial removal mechanisms but are sufficiently small to be subject to the molecular mechanisms of diffusion and Brownian motion. Penetration of particles through the fabric is relatively high during the initial moments of a gas cleaning cycle. Electrostatic forces may have an effect on particle removal, but neither the magnitude nor the mechanism of the effect is well understood.

After the first few minutes, accumulated particles bridge the pores and form a filter cake on the fabric. The filter cake has a smaller average pore size than the fabric and, apparently, sieving becomes the predominant removal mechanism. Some installations create an artificial filter cake by injecting lime or recycled ash into the gas stream entering the clean bag chamber. The artificial cake hastens recovery to full efficiency of the cleaned bags.

Bag cleaning is generally done by one of three methods: mechanical shaking, reverse air flow, or pulse jet flow. Mechanical shaking is accomplished by rapidly moving the frame, to which the tops of the bags are attached, back and forth in a rapid horizontal motion. The resultant flexing of the bag wall causes the filter cake to crack and fall off in chunks. Reverse air cleaning is accomplished by closing off a section of the baghouse from the boiler exhaust gas flow and forcing clean air (either filtered stack gas or ambient air) to flow backwards through the bags. The reversal of the gas flow causes the bag walls to flex (either expand or contract, depending on whether the normal flow to the inside or to the outside of the bag). The flexing cracks the cake which is then forced off of the bag by the reversed air flow. Pulse jet cleaning is accomplished by introducing a sudden blast of compressed air into the top of the bag. The pulse sends a traveling mechanical wave down the bag, cracking and flaking off portions of the filter cake. Some back flow through the bags is created aiding cake removal. Pulse jet cleaning can be accomplished without cordoning off the bags being cleaned.

Factors Affecting Performance. Once the filter cake is established on the bag surfaces, fabric filters remove 99% or more of all size of particles.

Penetration of particles is almost exclusively through rips in the fabric, leaks through poorly sealed connections, or through abnormally large (>200 microns) pores in the fabric. Particle size distributions downstream of fabric filters are nearly identical to those upstream. Maintenance is the most important aspect of operation of a baghouse. Other factors can be important. Sticky particles are poorly removed and can result in excessive pressure drops that can, ultimately, cause bag failures. Condensation of water can cause bag blinding, condensation of inorganic acids can cause corrosion and weaken some fabric materials. The temperature of the filter fabric must be kept above the acid dew point to avoid acid damage to the filters. The minimum acceptable temperature is dictated by the amount of sulfur trioxide in the flue gas which, in turn, is a function of fuel sulfur content. The acid dew point of fossil fuel combustion exhaust gases generally falls between 325° and 400°F.

Applicability to Industrial Boilers. The first fabric filters were installed on industrial processes approximately 100 years ago. The first installations on coal-fired boilers, at the impetus of tightening pollution abatement regulations, were made in the late 1960's. Performance has been encouraging and new installations are increasing. Existing applications range in size from small industrial boilers (5,000 actual ft^3/min) to large electric utility boilers (3×10^6 actual ft^3/min).

The ash from oil-fired boilers tends to be hygroscopic and sticky and tends to be irreversibly trapped in the interstices of the bag filter fabric (Reference 11). The few installations of baghouses on oil-fired boilers that have been attempted have met with limited success.

There is no known installation of a fabric filter on a gas-fired boiler. This is because gas-fired boilers, properly operated, emit minute quantities of particles.

Impact of Burning Hazardous Waste. The primary, expected effect of the combustion of hazardous waste in a boiler already equipped with a fabric filter is the potential for increased corrosion.

If the waste burned creates an oily or damp ash, blinding of the fabric filter could become a problem. The efficiency of fabric filters is relatively insensitive to particle size. They are as efficient for collection of fine particles as for larger particles. (Excessive amounts of fine particles will ultimately clog the fabric since they are not effectively removed during cleaning.) Thus, the efficiency of removal of metals by fabric filters is expected to be excellent.

However, unless the exhaust gas is cooled so as to condense vapor phase metals (e.g., Hg), these will not be collected. Vapor phase organic compounds will not be collected. Cooling the gases sufficiently to cause their condensation probably would result in blinding of the filter.

Wet Scrubbers

Process Description. A wet scrubber is a device for providing contact between a liquid and a gas in order to effect the capture of some constituent of the gas. The captured constituent may be solid, liquid, or gaseous. There are hundreds of designs in use most of which fall into one of four categories.

- Spray towers - high pressure liquid is sprayed into the gas stream in a relatively open chamber.
- Packed bed scrubbers - liquid flows downward through a porous bed of inert material, countercurrent to the gas flow.
- Flooded plate towers - similar to packed bed scrubbers except that the gas bubbles through holes in a discrete number of plates on which there is a layer of liquid.
- Venturi scrubbers - relatively low pressure water is admitted into the highly turbulent gas flow at the throat of a venturi.

Particle removal is effected by each of several processes. Larger particles are removed by impaction upon liquid surfaces. These may be film surfaces (as in a flooded plate scrubber) or droplet surfaces (as in a venturi scrubber). Smaller particles are deposited on the same liquid surfaces by diffusion or Brownian motion. If the gas being scrubbed is warm and moist then condensation occurs as it is cooled in the scrubber. The condensation, to some extent, occurs on the surface of the particles, thereby increasing their size (Reference 12). Increasing the size of the particles, by including them in the liquid phase, is the necessary operation. As dry particles, few have sufficient size to be easily separated from the gas stream inertially. Their inclusion in a water droplet yields a liquid/solid mixture that does have sufficient mass to be separated from the gas stream by relatively simple filters (de-mister pads) or cyclones.

Several studies have shown that the efficiency of particle removal is proportional to the total power expended by the scrubber. The power expenditure includes the pressure drop in the gas and liquid phases. It does appear, however, that the efficiency is also inversely proportional to the mass concentration of particles in the inlet gas stream. This implies that removal of the last few particles is at a great energy expense.

Scrubbers, no matter their design, do not remove small particles effectively at any reasonable power consumption. At practical energy expenditures, scrubbers are ineffective for removal of particles less than 0.5 to 1 micron in diameter (Reference 11).

Applicability to Industrial Boilers. Scrubbers, certainly, are applicable to coal-fired industrial boilers. They are small, relative to fabric filters and electrostatic precipitators, so, space allocation problems are less. However, scrubbers consume more energy than other control devices. The energy loss occurs both through the mechanisms of pressure drop in the gas stream and loss of stack draft that results from cooling of the gases. Especially high pressure drops are required to remove sub-micron particles. Boiler de-ratings, on the order of 5-10% have been required on large utility boilers to provide the power consumed by scrubbers. The usefulness of scrubbers for control of particles from oil- and gas-fired boilers is limited because of the small size, low concentration, and low density of the particles emitted. There are few existing installations.

Factors Affecting Performance. The sine qua non of scrubber performance is intimate contact between the gas and liquid phases. This contact may be effected by creating turbulence in the gas stream (i.e., venturi) with consequent loss of kinetic energy in the gas, by high pressure sprays to disperse the liquid in fine droplets, or by drawing the gas through a bed with a small average pore size with consequent high pressure drop.

Particle size is also important. Collection of particles of less than 1 micron diameter is at a unacceptably high energy cost (Reference 11). Particle density and tendency to absorb water, although these do not vary widely among coal-fired boilers, are important. Dense, hygroscopic particles are more easily scrubbed.

Impact of Burning Hazardous Waste. Of the four most commonly employed air pollution control devices on industrial boilers, only scrubbers have the capacity to remove the vapors of inorganic acids and volatile toxic metals that may be emitted. Corrosion, that might become a problem with the other types of control devices, can be overcome in a scrubber system by addition of alkali to the scrubber water. Should this become necessary it will exacerbate an already existing, spent scrubber liquor treatment and disposal, problem. Also, even though installed scrubbers will remove, at least some of, the vaporous metals, they operate at too low a pressure drop to remove the metal fume that consists of particles less than 0.5 micron in diameter.

Centrifugal Separation (Multiple Cyclones)

Process Description. Multi-tube cyclones (cyclones) consist of banks of tubes in parallel through which the exhaust gas flows. The tubes vary from 2 to 12 inches in diameter. Gas enters through an annular opening near the top of the tube, passes over spin blades (curved blades between the outer tube wall and the inner tube wall) which impart a tangential element to the gas velocity, flows into the chamber, and then back up through the central exhaust tube. The vortex created, causes particles, whose density is greater than that of the gas, to migrate outward to the tube wall. Collision with the wall absorbs their momentum and they fall into the hopper below. The literature on cyclones is extensive, techniques for prediction of collection efficiency based on; particle size and density; tube size; gas flow rate; and gas density are readily available (Reference 11).

Applicability to Industrial Boilers. As was noted earlier, nearly half of all coal-fired boilers are equipped with cyclone separators. They are relatively small, consume little power (pressure drops range from 3 to 6 inches w.c.) and have no moving parts that require maintenance. However, their collection efficiency is poor for particles of less than 10 microns in diameter. Thus, their effectiveness for control of oil- and pulverized coal-fired boilers is marginal. Even for stoker coal-fired boilers their prime utility is as a pre-cleaner for more efficient collection equipment.

Factors Affecting Performance. Particle size and density are the most critical factors affecting the performance of cyclones. Gas density and flow rate are also important: the latter more so, because cyclone performance falls off rapidly when the gas flow falls below its design value.

Impact of Burning Hazardous Waste. Corrosion of metal parts in general and cyclones in particular may be increased by combustion of hazardous compounds that contain Cl, P, and S.

The efficiency of cyclones for removal of small diameter particles and vaporous substances is nil. Thus, a large portion of the most toxic metals and all of the vaporous substances will penetrate the cyclones and be emitted into the environment.

Control Techniques for Nitrogen Oxides

Nitrogen oxides (NO_x) emitted from the combustion of fuel are formed by oxidation of organic nitrogen compounds in the fuel and by oxidation of atmospheric nitrogen (N_2) (Reference 2). Approximately 95% of the NO_x formed is nitric oxide (NO), the remainder is nitrogen dioxide (NO_2). The ratio of products varies somewhat. Coal and oil-fired furnaces apparently emit a smaller fraction of NO_2. The rate of formation of NO_x by both mechanisms (fuel and thermal) is a function of combustion conditions, primarily flame temperature and excess oxygen availability. Both fuel bound and atmospheric nitrogen are more resistant to oxidation than the organic components of fuels, so their oxidation is effected only at relatively harsh conditions. Therefore, it is possible to mitigate the combustion conditions in a boiler firebox somewhat to lessen formation of nitrogen oxides without reducing the efficiency of fuel combustion. In fact, reducing the excess air (one NO_x reduction technique) may increase the efficiency for the boiler.

Five techniques for reducing NO_x emissions are currently practiced (Reference 2):

- Low excess air (LEA)
- Staged combustion (SC)
- Flue gas recirculation (FGR)
- Low NO_x burners (LNB)
- Reduced air preheat (RAP)

Each of these techniques is discussed below.

Low Excess Air

Process Description. Most industrial boilers are routinely operated at higher excess air rates than are recommended by the manufacturers of the boilers. Operation at higher than design excess air provides a cushion against smoke emissions during sudden load changes, lessens the need for careful operator attendance, and obviates the requirement for sophisticated (and expensive) combustion air controls. High excess air also reduces the thermal efficiency of the boiler by increasing the amount of hot gas exhausted, and increases the amount of residual oxygen available for oxidation of fuel and atmospheric nitrogen.

Reduction of excess air in small, relatively simple fire tube and package water tube boilers is accomplished by closing down the inlet vanes on the forced draft fan or by closing down the vanes on the windbox. On larger, more sophisticated boilers, the forced and induced draft fan speeds can be reduced.

Development Status. Reduction in the excess air is being applied widely to improve thermal efficiency and thereby reduce fuel costs.

Applicability to Industrial Boilers. Lowering excess air is applicable to all industrial boilers that have been operated at higher than design air levels. It is recommended that automated air controls (oxygen trim systems) be installed to ensure safe, smokeless operation.

Factors Affecting Performance. At any boiler load, the percent reduction of NO_x emissions is directly proportional to the reduction in excess air. In coal-fired boilers, a decrease of 1% in the flue gas oxygen concentration can result in a 5% reduction in NO_x emissions.

Impact of Burning Hazardous Waste. It has been hypothesized that reduction in the available oxygen in the combustion zone might reduce the oxidation of hazardous compounds for the same reasons that it reduces oxidation of nitrogen. This effect was not observed at one of the sites tested for this effort where excess air was varied at constant boiler load. The destruction efficiency of hazardous materials with the oil-fired boiler at 50% excess air (7% O_2) was not discernably different from the destruction efficiency with the boiler at 17% excess air (3% O_2). The determination of destruction efficiency was made by comparison to the flow rates of the hazardous compounds in the stack gas to their flow rates in the fuel stream. It is possible that their destruction was by some means other than oxidation.

Staged Combustion

Process Description. Staged combustion consists of reducing the air flow through the burner port (burner box) to a level flow needed to completely oxidize the fuel. Secondary air is added to the flame zone to provide the additional oxygen required. The practice has two effects: it reduces the temperature and oxygen concentration in the primary flame zone and it diffuses the flame into a larger volume. The reduced temperature and oxygen levels reduce formation of NO_x. The more diffuse flame provides a larger volume from which heat is radiated, allowing more rapid cooling of the flame and thus, a shorter time for oxidation of nitrogen. Staged combustion is nearly always applied in conjunction with low excess air. The secondary (staged) air can be introduced through the side wall or the top of the flame zone. The effect is inherent in coal-fired stoker boilers but may be enhanced by reducing underfire air flows.

Development Status. The status of development of technology to implement staged combustion in various types of industrial boilers is summarized in Table 3.10.

Applicability to Industrial Boilers. Staged combustion normally can be implemented on oil and gas-fired boilers. Installation of an oxygen trim system to monitor and control the flow rates of primary and secondary combustion air is necessary to prevent excessive smoke and combustible gas emissions.

Implementation of staged combustion on pulverized coal-fired boilers can result in increased slagging and corrosion and pose the same, poor combustion efficiency problems. These again can be alleviated by installation of automated combustion air controls, and by installation of compartmented windboxes to assure equal distribution of combustion air among burners.

TABLE 3.10

DEVELOPMENT STATUS OF STAGED COMBUSTION FOR APPLICATION TO INDUSTRIAL BOILERS - 1982

(Reference 2)

	Coal-Fired Industrial Boilers		Oil- and Natural Gas-Fired Industrial Boilers		
Boiler Type	Packaged and field erected stokers	Field erected pulverized	Field erected watertube	Packaged watertube	Packaged firetube
Status	Available but not implemented	Available and implemented	Available and implemented	Available and implemented	N/A R&D status

N/A = not available

Stoker coal-fired boilers appear to present the most difficult case for retrofit of staged combustion. In general, the overfire air ports are not adequately designed and positioned to provide efficient secondary combustion. In addition, if the primary (underfire) air is reduced too much, clinker forms on the grates requiring additional labor to manually break the lumps. Emissions of NO_x are reduced by implementation of staged combustion in most stokers, but the emissions reductions are not consistent with increased staging.

Factors Affecting Performance. Utility boiler experience has shown that if the secondary air ports are located too close to the connection bank high steam temperatures result. If the secondary air is introduced too close to the burners, the staging is compromised and optimum NO_x reductions are not realized.

With distillate oils or gas fuels, efficient smoke-free operation can be attained with the primary air as little as 90% of theoretical combustion air. Primary air must be 105% of theoretical combustion air to prevent slagging and corrosion in residual oil- and coal-fired boilers.

Impact of Burning Hazardous Wastes. As with all approaches to reducing NO_x emissions, the intent of staged combustion is to effect lessened oxidation of nitrogen by reducing the flame temperature and the availability of oxygen in the flame. Mitigation of the flame conditions may be inimical to destruction of hazardous compounds. To date, one boiler practicing staged combustion has been tested. The unit was an 86×10^6 Btu/hr, gas-fired water tube boiler that was co-firing aniline wastes. The waste stream was spiked with chlorinated hydrocarbons for the test. The DRE of the wastes exceeded 99.99% for all compounds (except benzene, a common PIC of fuel burning for which the DRE was 99.98%) for all runs. There was no discernible difference between the DRE observed during staged combustion and unstaged combustion runs.

The second potential impact is accelerated corrosion from hydrochloric, nitric, and phosphoric acids formed when hazardous wastes containing Cl, N, or P are burned. This effect will be most pronounced in residual oil- and coal-fired boilers that are subject to enhanced corrosion during phased combustion.

Flue Gas Recirculation

Process Description. Recirculation of flue gas into the burner air reduces NO_x formation by reducing the concentration of oxygen available to react with nitrogen. Recirculation also provides a larger mass of combustion gases to absorb the heat of combustion. The overall effect is to lower the average combustion chamber temperature, again reducing NO_x formation. Physically, the system is simple. It requires only that ductwork be provided to return some of the flue gas to the forced draft fan, and that the fan be increased so it is capable of forcing the extra gas through the windbox.

Applicability to Industrial Boilers. Flue gas recirculation is commercially available and applicable to any distillate oil or gas-fired boiler. It is avaliable but much less effective for reducing NO_x emissions from firing residual oils and coals that contain fuel bound nitrogen.

The higher operating temperature impressed upon the forced draft fan reportedly causes it to erode more rapidly than normal (Reference 2). Flame instability is lessened if recirculation exceeds 20 to 25% of the combustion air.

Factors Affecting Performance. Recirculation rate is the only variable in this system. The percent reduction of NO_x emissions from distillate oil- and gas-fired boilers is approximately linear with recirculation rate up to 30% flue gas recirculation. The percent reduction of NO_x emissions is approximately 10 for flue gas recirculation rates and between 15 and 25% in residual oil-fired boilers.

Impact of Burning Hazardous Wastes. The inorganic acids formed when compounds containing Cl, N, or P are burned will contribute to corrosion of the recirculation duct work and the forced draft fan. Addition of hazardous wastes, especially those with high water contents, may contribute to the flame instability that has been observed at high recirculation rates.

Low NO_x Burners

Process Description. Low NO_x burners are designed to accomplish the functions of low excess air flue gas recirculation and staged combustion within the burner itself. They incorporate techniques such as delayed fuel/air mixing, internal gas recirculation, flame cooling and dispersion surfaces, off-stoichiometric fuel/air mixing to reduce flame temperatures, and oxygen availability in the high temperature zone. They differ from the previously discussed techniques only in that these functions are accomplished internally (in the burner) rather than in the boiler.

Applicability to Industrial Boilers. Low NO_x burners are available for relatively small industrial boilers. The size of available low NO_x burners has inhibited their use in larger boilers because of the cost of construction of multiple burner boilers. Single burner, shop-erected boilers up to 250 x 10^6 Btu/hr are less costly than field-erected multiple burner boilers of equal size.

Factors Affecting Performance. Low NO_x burners are affected by the same operating parameters as the three techniques previously discussed. Greater dispersion of the flame may cause it to impinge upon the back wall of the furnace. Higher temperatures appear to cause increased NO_x emissions.

Impacts of Burning Hazardous Wastes: Burning hazardous materials will impact low NO_x burners the same way it will impact other NO_x control techniques, i.e., possible: increased corrosion, low destruction efficiency and flame instability. No testing of units burning hazardous wastes in low NO_x burners has been reported.

Reduced Air Preheat

Process Description. Most boilers larger than 50 x 10^6 Btu/hr recover some heat from the flue gases, either by combustion air preheaters or by feedwater heaters (economizers). Selection of an economizer rather than an air preheater lowers the heat input to the flame and thereby reduces oxidation of atmospheric nitrogen. It does not appear to reduce NO_x formation from fuel-bound nitrogen and, therefore, is less effective for residual oil-fired and coal-fired boilers.

Development Status. Both air preheaters and economizers are well-developed technologies. In most cases, the purchaser of a boiler can opt for one as easily as the other.

Applicability to Industrial Boilers. The technique is applicable to new boilers. Retrofit of existing boilers is not likely to be economically feasible.

Factors Affecting Performance. The degree of reduction of NO_x emissions is a function of the degree of reduction of air preheat. Normally, the air preheater either exists or it does not, and the combustion air temperature is either ambient or about 450°F. Gas and distillate oil-fired boilers with no air pre-heat emit approximately half as much NO_x as boilers with air preheat. As was mentioned, there is little or no affect on formation of NO_x from fuel bound nitrogen. Therefore, the percent reduction of NO_x from residual oil and coal-fired boilers is less, although the absolute reduction is probably equivalent.

Impact of Burning Hazardous Waste. Other than possible increased corrosion of the economizer and boiler, combustion of hazardous wastes should have no effect on the performance of a boiler employing reduced air preheat. Insufficient test data have been collected to demonstrate the effect of reduced flame temperature on the efficiency of destruction of hazardous compounds.

POTENTIALLY APPLICABLE CONTROL EQUIPMENT

Available data indicate that combustion of hazardous waste streams in industrial boilers contributes no fly ash to the boiler exhaust, other than the amount that is expected during combustion of virgin fuels of comparable ash content. Compliance with EPA and state particle emission regulations should be attainable by the same means employed for boilers burning virgin fuels. There may be some wastes (e.g., paint manufacturing waste, degreaser waste) that contain abnormally high concentrations of ash and inorganic matter that, when burned, emit excessive amounts of fly ash. Unless these wastes also contain high concentrations of organic chlorine or toxic metals, the application of one of the control devices discussed previously should be sufficient.

Existing baghouses and electrostatic precipitators (ESPs), where they are installed, are adequate to control the emissions of the relatively non-volatile, toxic metals. ESPs are less efficient for removal of particles of approximately 0.5 micron diameter than for other sizes; but, are approximately 90% efficient for these particles. Thus, even if as much as 80% of a toxic metal is concentrated in particles of less than 1 micron diameter, the overall penetration of the toxic metal will be less than 10%. The efficiency of baghouses is relatively unaffected by particle size and should be in excess of 99%.

The presence of hydrochloric acid (HCl) alone in the exhaust gas also presents no difficulty to conventional control devices. Relatively simple water flooded packed towers can achieve 98% efficiency if the scrubber water blowdown rate is sufficient to keep the HCl concentration below 2% (Reference 12). Single pass scrubbers using caustic liquor can easily attain 99% efficiency.

In the case that the hazardous waste contains high concentrations of chlorine and toxic metals, presently installed equipment will prove inadequate. This case will require removal of vapor phase HCl (and perhaps vapor phase metals) and highly efficient removal of the small particles that will contain most of the volatile toxic compounds. Of course, it would be possible to achieve adequate removal of both types of pollutants (vapors and fine particles) by series installation of a scrubber and an ESP or baghouse; but this may be more expensive than one of several recently demonstrated devices that have demonstrated efficient removal of both particles and gases.

Emissions of nitrogen oxides (NO_x) during combustion of wastes having a high nitrogen concentration is the second case that may require application of advanced control technology. Of the five combustion practices that are currently implemented for control of NO_x emissions, three (low excess air, flue gas recirculation, and reduced preheat) are effective for reduction of thermal oxidation of atmospheric oxygen but less effective for reducing oxidation of fuel-bound nitrogen. Of the two techniques (staged combustion and low NO_x burners) that have demonstrated capability for reducing oxidation of fuel-bound nitrogen only one, staged combustion, has been evaluated in a hazardous waste service. These tests were performed on a gas-fired boiler in which aniline production wastes (nitrobenzene and aniline) were being co-fired. The nitrogen contributed by the waste stream amounted to approximately 1.5% (wt/wt) of the total (gas plus waste) fuel - a concentration that is typical of coals. The test results showed NO_x emission rates to be about 1.1 lb $NO_x/10^6$ Btu when combustion staging was not implemented and about 0.35 lb $NO_x/10^6$ Btu when the combustion was staged.

Thus, staged combustion reduced NO_x emissions sufficiently to effect compliance with emissions limits placed upon a fuel with a comparable nitrogen content, but not sufficiently to comply with emissions limits for either gaseous or liquid fuels. Note that the regulations cited apply only to large ($>250 \times 10^6$ Btu/hr) boilers but that regulatory alternatives for smaller boilers are presently being considered. Currently proposed regulation of industrial boilers larger than 100×10^6 Btu/hr heat input limit NO_x emissions to:

Fuel	NO_x Emission Limit ($lb/10^6$ Btu)
Gas and Distillate Oil	0.1
Residual Oil	0.3 - 0.4[a]
Coal (Stoker)	0.6
Coal (Pulverized)	0.7

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[a] Variable - depends upon fuel nitrogen content.

Obviously, this boiler would not meet the proposed regulation for gas-fired boilers. However, the proposed NO_x regulation contains a provision that allows holders of RCRA permits to obtain a variance based upon their demonstration that the best available technology will not bring them into compliance with the NO_x emission limit while maintaining adequate DRE of the hazardous material. Such conflicts will be resolved on a case by case basis.

Advanced Control for Vapor Plus Small Particle Emissions

Many novel, air pollution control devices have been developed and tested over the past several years under the EPA Research on Novel Device for Particulate Control program. These were considered in relation to control of emissions from the incineration of hazardous waste by Branscome, et al. (Reference 12). Several of these novel devices appear to be applicable to the possible need for simultaneous control of vapors (HCl and vapor phase toxic metals) and the several toxic metals that appear to concentrate into particles less than 1 micron diameter. These novel devices are in various stages of engineering development from bench-scale to full-size industrial installations. Pilot-scale models are available for nearly all, but only a few installations exist. The discussion in this section is restricted to those for which encouraging pilot-scale or full-scale results have been reported and which show the greatest promise for practical, economical application within the next year or two.

Wet Electrostatic Precipitators

Process Description. Electrostatic precipitation was discussed in the previous section. Most of that discussion applies directly to wet electrostatic precipitators (ESPs). The boiler exhaust gas is cooled and saturated with water vapor in a quench chamber upstream from the wet ESP. As the particle laden gas flows through the ESP it is subjected to a high voltage field that impacts electrostatic charges to the particles in a manner analagous to the dry ESP. The collection electrodes, however, are flushed continuously with water (or reagent liquid). As particles migrate to the collection plate, they become entrained in the liquid and are removed with it. The liquid may be clarified and recirculated.

Because the collection plates are continuously wetted, the wet ESP also serves as a packed bed gas absorber. Soluble gases (e.g., HCl, SO_2, NO_2) dissolve in the water and are removed along with the particles.

Development Status. Several companies have produced pilot-scale wet ESPs and a few full-scale units have been installed, mostly in service as demisters.

Applicability to Industrial Boilers. Wet ESPs are thought to be directly applicable to industrial boilers. Because the incoming gases are cooled and saturated, their volume is reduced. Therefore, a wet ESP can be smaller than a dry ESP. Pilot tests of two units, installed on a municipal incinerator demonstrated overall particle collection efficiencies ranging from 94.3 to 98.8%. Unfortunately, particle size measurements were not made at the outlet so that expected efficiency of removal of fine particles was not confirmed. The efficiency of removal of sulfur dioxide ranged from 70 to 78%; of HCl from 84 to 98%, and one unit reportedly removed 39% of the NO_x.

Factors Affecting Performance. The factors affecting the performance of dry ESPs will, for the most part, affect the performance of wet ESPs. The exceptions are that reentrainment due to low resistivity and gas scrubbing of the collection plates will be less in the wet ESP. Once a particle becomes entrained in the liquid that is flushing, the collection plate no longer needs to be held to the plate electrostatically. Therefore, low resistivity particles will not be as readily lost.

Since the wet ESP will have been selected only in the case where acid gas (HCl) removal is necessary, its design should incorporate corrosion resistant materials.

Steam Hydro and Free Jet Scrubbers

Process Description. These devices are similar in concept; water is injected into a gas stream as that stream enters a jet nozzle. The free jet scrubber relies upon the turbulent mixing that occurs in the nozzle to provide intimate gas/liquid contact. The steam hydro scrubber directs the scrubber water flow onto a supersonic steam jet in order to break the water into even smaller droplets. The steam ejector also provides the draft so that no ID fan is needed. Mixing occurs in the set nozzle throat providing for absorption of dust particles and soluble gases. The free jet scrubber is normally provided as a tandem, two jet nozzles with water sprays, in series. The incoming gases are quenched by water sprays prior to entry into either device. Both provide cyclone separators to remove the water droplets (and entrained particles) from the gas stream. The devices are essentially venturi scrubbers. Their manufacturer claims that the tandem free jet scrubber has a lower energy requirement than other scrubber types for equivalent particle removal efficiency. The use of supersonic steam in the steam hydro scrubber results in a power consumption of about 10 times that of an air ejector venturi, albeit particle collection efficiencies are better.

Development Status. Applications of the steam hydro scrubber are usually limited to specialty problems that require reliability and efficiency. They also are applicable where a source of waste heat can be captured to provide the needed steam. Free jet scrubbers have been commercially installed on radioactive waste, PCB, and municipal waste incinerators. As mentioned, both devices are essentially similar to venturi scrubbers and consist largely of existing technology.

Applicability to Industrial Boilers. Either of these devices ought to be applicable to industrial boilers though no known installation exists. Both were pilot tested at a municipal incinerator. The free jet scrubber reduced outlet particle concentrations to 0.014 to 0.032 gr/dscf at pressure drops between 30 and 40 inches w.c. The steam hydro scrubber gave overall particle removal efficiencies of 99.9%, the highest attained by any scrubber in the EPA novel control device research program.

Factors Affecting Performance. As with other scrubbers, energy consumption is the most important factor affecting the efficiency of particle removal by these devices. The case where the boiler exhaust gas contains a high concentration of inorganic acids (HCl) can be accommodated by use of a caustic solution in lieu of water scrubbing liquid and by fabrication of the unit from corrosion resistant materials.

Ionizing Wet Scrubbers

Process Description. Ceilcote has developed an ionizing wet scrubber (IWS®). The device is conceptually similar to a two-stage ESP. The gas to be cleaned is first quenched, if necessary, to lower its temperature; it then passes through a high voltage ionizer section in which the entrained particles become charged and, finally, through a cross flow packed bed scrubber where the charged particles are attracted to and absorbed by a grounded scrubber liquor. The scrubber liquor may be water or water augmented with caustic (lime) for improved HCl collection.

Development Status. The IWS® is a combination of two existing technologies: electrostatic charging of particles and packed bed scrubbing. As of March 1982, the company listed over 30 installations, including 13 at municipal and industrial waste incinerators. The device can be considered to be existing technology.

Applicability to Industrial Boilers. Although no installations are known, the IWS® appears applicable to industrial boilers. Natural draft is lost because of the heat removal that occurs in this (or any) scrubber. However, the low pressure drop and total energy consumption reported are attractive.

Factors Affecting Performance. The incoming gas stream must be conditioned to reduce its temperature, remove large (>5 microns) particles, and to effect condensation of volatile organic material in order to attain maximum efficiency. Company literature states that a one-stage system will remove 75 to 90% of 0.5 micron particles and that a two-stage unit will remove 93 to 97%. Results of tests of a two-stage unit in service on a refractory kiln showed only 50% efficiency of collection of 0.5 micron particles.

Dry Scrubbers

Process Description. The term dry scrubber refers to a device wherein a powdered absorbing reagent is dispersed into the pollutant laden gas stream before the gas enters a baghouse. For example, lime can be injected to the exhaust of a combustion source to absorb, with reaction to $CaCl_2$, the HCl generated during combustion of chlorinated compounds. There are several designs which vary primarily in the means by which the reactant powder is dispersed. Dispersion equipment used includes centrifugal atomizers, spray nozzles, and venturi throats. At least one manufacturer injects the reactant as a slurry which dries in the gas stream before removal by the baghouse.

Development Status. Dry scrubbing is a relatively new technology so there is not a large base of published information about their performance. A few installations (mostly on hazardous waste incinerators) have shown promise.

Applicability to Industrial Boilers. There is no known installation on industrial boilers burning hazardous waste. Although several (about a dozen) have been sold for the purpose of flue gas desulfurization, the technical and economic viability for controlling HCl emissions from a boiler using dry scrubbing has not been demonstrated.

Factors Affecting Performance. Operation in an HCl laden gas has been problematical. The HCl is, of course, corrosive and the reaction product ($CaCl_2$) is delinquescent and corrosive. High chloride is damaging not only to metallic structural members but also to the bag material. Two materials, polypropylene and Teflon®, appear to be satisfactory. The former should not be used at temperatures above 235°F. The latter may be used at higher temperatures but is more expensive. However, unless the stack gas temperature is reduced, from the 350° to 400°F typical of small boilers, the efficiency of removal of volatile metals will not be optimum.

Ammonia Injection

Process Description. Ammonia (NH_3) injection ivolves the noncatalytic decomposition of NO_x in the flue gas to nitrogen and water using ammonia as the reducing agent. This technique is often referred to as selective noncatalytic reduction or thermal $DeNO_x$. At a mole ratio of 1.5 moles NH_3 per mole NO_x, over 40% of the NO can be reduced if the reaction is designed to take place at a location in the boiler where the temperature ranges from 1700° to 1800°F. Outside the range of 1650° to 2000°F less than 10% of the NO_x in the flue gas can be reduced to nitrogen and water by ammonia injection.[13] Since ammonia must be injected into the section of the boiler that is within the narrow optimal temperature window, some curtailment of load following capability may result.

Development Status. Ammonia injection is applicable to all industrial boiler types and fuels where there is access in the proper temperature range. Although this technique is commerically offered, it is not currently applied to any domestic operating industrial boiler.[13] Ammonia injection has been installed on three gas- and oil-fired boilers ranging in size from about 16 to 79 MW (55 to 270 x 10^6 Btu/hr) thermal input in Japan. In the U.S. this technique has been investigated only on pilot-scale facilities, except for one commercial installation on a crude oil-fired thermal enhanced oil recovery steam generator. This installation is not currently operating because of problems experienced with the steam generator.

Applicability to Industrial Boilers. Application of ammonia (NH_3) injection to industrial boilers is complicated by the frequent load swings these boilers typically undergo. Since the reaction between NH_3 and NO is efficient in only a narrow temperature range development of an injection grid is necessary so that the injection can be made in the appropriate furnace zone as load varies.

Factors Affecting Performance. The required reaction temperatures for noncatalytic decomposition of NO with ammonia are found in different areas of the boiler depending on its design and operating load. For example, at full load these temperatures occur in the convective section of both packaged and field-erected watertube boilers. Changing boiler load, however, causes a shift in the temperature profile through the boiler, reducing NO_x removal to below 30%. For small firetube boilers, optimal ammonia injection temperatures occur directly in the firebox. In this area of the boiler, cross-sectional flue gas temperatures are often not uniform, causing significant degradation of the NO_x reduction performance to below 10%.[13]

For new units, multiple ammonia injection grids can be strategically designed and located to compensate for temperature gradients and shifts in temperature profiles with changing loads. This technique, however, has not yet been demonstrated.[13]

Other factors affecting performance include NH_3 injection rate and residence time at optimal temperature. The optimal NH_3/NO_x molar ratio has been established to be approximately 1.5, with no additional NO reduction gained by increasing the ratio to 2.0. Maximization of the residence time at optimal temperature can be achieved by proper location of the multiple injection grids. A cross-sectional temperature profile will be required for each boiler design to identify these locations.[13]

Effects of Burning Hazarous Wastes. Sulfur-containing wastes present a potential problem. The formation of ammonium sulfate or ammonium bisulfate can cause plugging of an air preheater or corrosion of boiler parts. Increased frequency of water washing will minimize this problem. To insure that ammonia emissions to the atmosphere are minimized, ammonia sensors and feedback control systems for the injectors may be required.

Selective Catalytic Reduction

Process Description. Selective catalytic reduction (SCR) is a technique involving reduction of the flue gas NO_x concentration by reacting NO_x with NH_3 in a catalytic reactor. With the exception of the use of a catalyst it is similar to the ammonia injection NO_x control technique described above. In this process, ammonia, taken from a liquid storage tank and vaporized, is injected at molar ratios of 0.7-1.2 moles NH_3 per mole of NO_x and mixed with flue gas prior to the reactor. The flue gas passes through the catalyst bed where NO_x is reduced to N_2. Typically, a 1.0 mole ratio of NH_3 to NO should yield a 90% reduction in NO_x emissions. The flue gas exits the reactor and is sent to the air preheater and, if necessary, further treatment equipment for removal of particulates and SO_2. Flue gas must enter the reactor at 350-400°C since it is in this temperature range that the catalysts show the optimum combination of activity and selectivity. The catalysts used in most SCR processes are oxides of non-noble metals which have shown the best combination of high reactivity and resistance to SO_2 and SO_3 poisoning.

Development status. SCR is not considered a commercially demonstrated control technology for coal-fired sources in the U.S. SCR processes have been used commercially in Japan on gas-, distallate oil-and residual oil-fired industrial boilers and SCR processes on coal-fired utility boilers are under construction. Ongoing studies in the U.S. are investigating NO_x only and NO_x/SO_x SCR performance with coal combustion in pilot-scale facilities. There is no full-scale U.S. or Japanese SCR installation with documented performance in accordance with EPA test methods, although removals in excess of 90% have been reported for Japanese gas- and oil-fired boiler SCR applications. EPA is sponsoring two (2) pilot-scale evaluations of SCR technology on coal-fired utility boilers. The Electric Power Research Institute (EPRI) is also sponsoring a coal-fired utility boiler SCR pilot plant.

Applicability to Industrial Boilers. SCR is applicable to all industrial boiler types. The particular catalyst formulation and shape as well as reactor type will be dictated by the fuel fired. Variables associated with boiler type that can affect the performance of SCR systems are flue gas flow rate, NO_x concentration, and boiler load variability.

The flue gas flow rate and NO_x control level determine the catalyst volume necessary. Increases in either increase the required reactor size. The NO_x concentration is primarily a function of fuel type used.

The system will work well with gas- or oil-fired units using conventional catalysts and fixed bed reactor designs. With coal firing, potential ash plugging problems dictate the use of one or more of the following approaches:

- o Operation of the NO_x control system downstream of an efficient and reliable particulate removal device.
- o Use of a moving bed design which permits the periodic removal of catalyst for cleaning.
- o Use of a catalyst shape that does not collect the entrained particles present in the flue gas as they pass through the catalyst bed.

Factors Affecting Performance. An important design variable with catalytic systems is the space velocity which is expressed as the volume of catalyst required to treat one volume per hour of flue gas. Space velocity varies with catalyst formulation, catalyst shape, and control level. Both NH_3/NO_x ratio and space velocity will range from approximately 1.5 to 8 for control levels of 70 to 90%.[14] The operating temperature range for most of these processes is about 300-500°C, though more efficient NO_x removal usually occurs in the higher portion of this range. To maintain the reactor temperature at desirable operating levels during periods of reduced boiler load, most process vendors recommend bypassing a part of the flue gas around the economizer. In some pilot-plant and larger operations, auxiliary heaters have been used to maintain reactor temperatures during turndown.

Impact of Burning Hazardous Wastes. The most probable impact of hazardous wastes on SCR systems is catalyst degradation by metals and by the high chloride concentrations that result form combustion of chlorinated compounds. Disposal of spent catalysts may be an environmental concern since some of the non-noble metals used in their formulations are hazardous. This problem will be exacerbated if combustion of hazardous wastes increases the frequency of replacement. In addition, if metals in the hazardous wastes accumulate in the catalyst the problems associated with catalyst disposal will be exacerbated.

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SECTION 4

DESTRUCTION EFFICIENCY AND CONTROL TECHNIQUES

The EPA Office of Solid Waste recognized the need to collect emission data from boilers burning hazardous wastes as fuels. Since little data existed, EPA developed a program to test representative industrial boilers burning a variety of waste streams. This section evaluates the sampling and analytical procedures used to collect the field data and summarizes the results of test burns conducted at 15 sites. This section also includes a discussion on the types of system modifications that will be required in order to burn hazardous wastes in existing boilers. This will include modifications to the boiler, as well as the need for pretreatment and air pollution control equipment.

EVALUATION OF TEST METHODS

The most widely employed procedures for measurement of the rates of emissions of organic substances from combustion sources are the Modified Method 5 (MM5), the volatile organic sampling train (VOST) procedures, and an adaptation of the VOST protocol for short sampling times and field analysis called Mini-VOST procedure. These methods are conceptually similar; both sampling trains consist of a particle filter, a condenser, a bed of porous polymer sorbent, and a condensate trap. Their differences lie in their size, sorbent, and analytical techniques. Some of the salient attributes of the two methods are compared in Table 4.1. The strengths and weaknesses of these two methods are discussed in this section.

Modified Method 5 (MM5)

Description of Method

This method is an adaptation of EPA Method 5 (40 CFR Part 60) modified to obtain samples for organic compound analysis as well as quantification of particulate matter emissions. The adaptation (Figure 4.1) is the addition of a sample gas condenser and a sorbent resin module between the heated filter and first impinger of the Method 5 train. The sorbent resin most commonly used for hazardous waste combustion evaluation is XAD-2 which is highly effective at trapping organic compounds with boiling points greater than 100°C.

The sample is collected by isokinetically drawing stack gas through a heated glass or quartz probe, through a heated glass fiber particle filter and then to the condenser/resin module. The sample gas is kept above 120°C

TABLE 4.1

COMPARISON OF MM5 AND VOST PROCEDURES

Feature	MM5	VOST	Mini-VOST
Sampling Rate	14-40 lpm	0.5 to 1 lpm	1.0 lpm
Sorbent	XAD-2	Tenax®-GC	Tenax®-GC
Analysis of Condensate	yes	no	no
Sample Recovery Technique	sorbent extraction	thermal desorption	thermal desorption
Analysis	GC or GC/MS	GC/MS	GC/HECD
Boiler Point of Analytes	>100°C	30° to 100°C	30° to 100°C
Sampling Duration	1 to 4 hr	0.3 to 1 hr	10 min

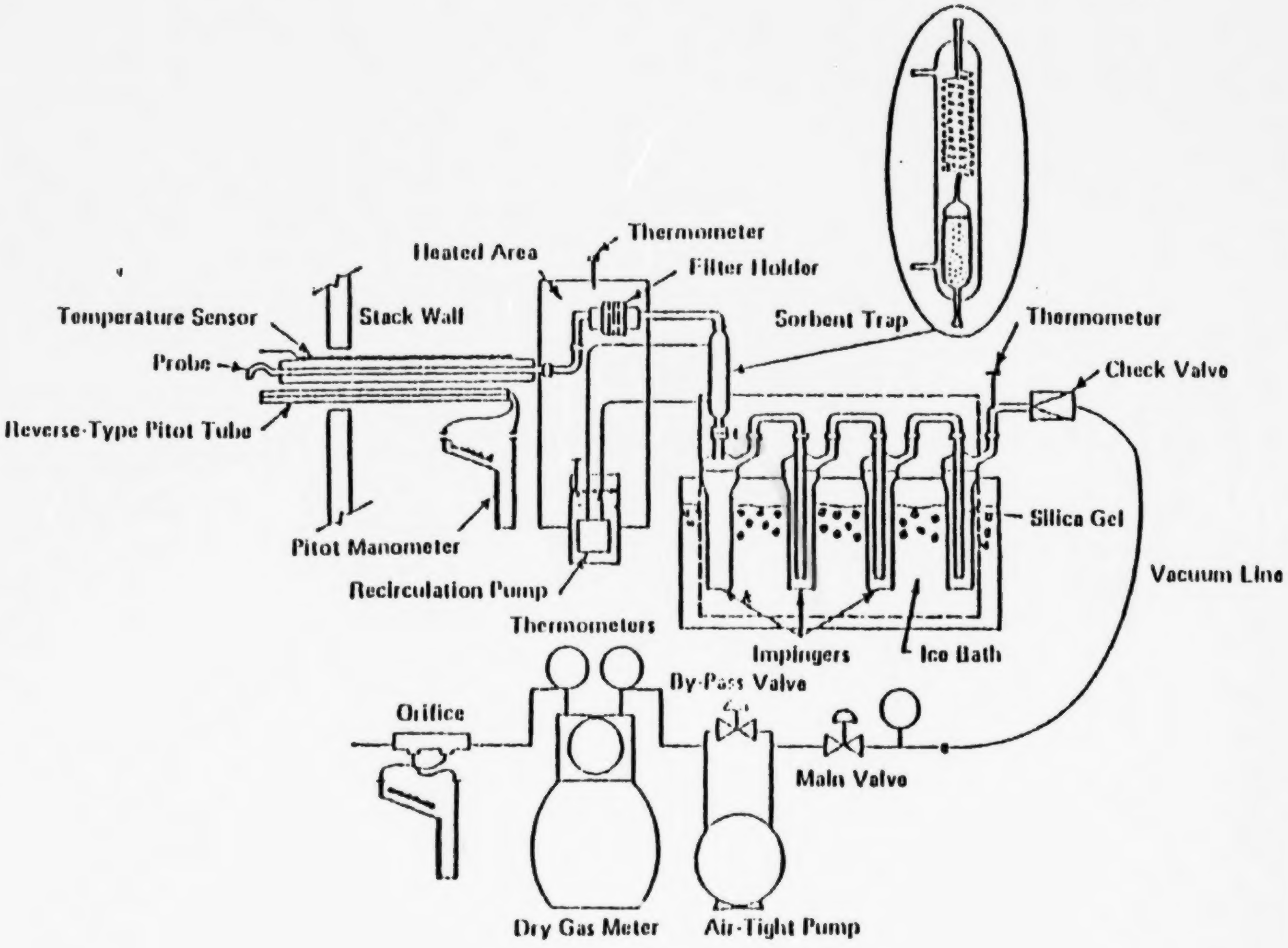

Heated Area
Thermometer
Filter Holder
Sorbent Trap
Thermometer
Check Valve
Temperature Sensor
Stack Wall
Probe
Reverse-Type Pitot Tube
Pitot Manometer
Recirculation Pump
Silica Gel
Vacuum Line
Thermometers
Impingers
Ice Bath
By-Pass Valve
Orifice
Main Valve
Dry Gas Meter
Air-Tight Pump

FIGURE 4.1

MODIFIED METHOD 5 TRAIN (MM5)

until it reaches the condenser where it is cooled to <20°C. Filtration temperatures up to 205°C are used to minimize organic species condensation prior to the condenser if this does not interfere with the determination of particulate matter. The sample gas and condensate pass through a resin bed located below the condenser allowing the condensate to percolate through the bed and collect in an impinger or condensate trap underneath the resin module. The sample gas is then bubbled through two more impingers in the conventional Method 5 configuration for acid gas and additional moisture removal.

Samples are analyzed by performing solvent extractions on the probe and filter material as one fraction, the resin as a second fraction, and optionally on the condensate and impinger catches as third and fourth fractions. The solvent extracts are concentrated and may be combined and analyzed by gas chromatography using mass spectrometers, flame ionization detectors, or electron capture detectors, as appropriate, for the organic compounds of interest.

Procedure Standardization

The construction and operation of a Method 5 train is well known and well described in the literature. The train operation, sample recovery, choice of sorbent resin, and analytical method to be used in a given application of MM5 are not specified. At this time, a single description of how the MM5 train is or may be used is not available. The sample collection aspects including resin choice, are discussed in various publications, but the sample recovery, analysis, and data reduction are not well described.

The Method 5 train and sample collection scheme has become the standard for measurement of emissions of particulate matter and it is not surprising that modifications to it have evolved in attempts to quantify other types of emissions using the same equipment and techniques. Method 5 is written as a compliance test method for certain specific categories of sources subject to NSPS. This specificity has not been established for the MM5 procedure as applied to hazardous waste DRE sampling in part because at least some of the measurement objectives will be different from test to test. Many of the objectives will be the same and these need to be identified and the method written to ensure that the goals are clear.

First, the relative priorities of measuring particulate matter and organic compound emissions need to be set. Most often these will not conflict and no sacrifice of one measurement for another is needed. In the cases where some relatively significant quantity of organic chemical of interest may be found in the "front half" (probe, filter, connecting glassware) of the Method 5 train then the accuracy of particulate matter measurement may need to be sacrificed to obtain the S-VOC data. Examples are not brushing the probe to avoid contamination, removing some particulate matter with the solvent used for S-VOC recovery, and/or operating the heated portion of the train at higher than normal temperature (e.g., 205°C) and vaporizing particulate matter which would otherwise deposit in the front half of the train. In the case of oil-fired boilers, much of the particulate matter is carbonaceous with little inorganic ash and the material contains straight chain and aromatic hydrocarbons which may or may not be collected in the front half depending on the filtration temperature. This is different from a coal-fired unit where the ash is mostly (typically >95%) inorganic matter. If

POHCs or PICs to be measured from hazardous waste combustion are to include naphthenic or paraffinic hydrocarbons, then whether the boiler is oil- or coal-fired will probably affect the sampling and analysis scheme.

Selection of POHCs and PICs also bears on the choice of a suitable sorbent resin. Generally, the MM5 is used to sample for PICs - the higher boiling compounds, but it is also used to collect samples for certain Appendix VIII compounds, e.g., toluene, monochlorobenzene. XAD-2 is the resin most commonly used and recommended as a general purpose sorbent when solvent extraction is the means of sample recovery. XAD-2 was selected for its sorbent properties, ease of cleaning, and sample recovery efficiency. Others are also used, for example Tenax®-GC, if thermal desorption is the sample recovery procedure. However, selection of a sorbent resin usually involves a great deal of time and effort (literature and laboratory research) that is usually not practical on a case-by-case basis.

The last major uncertainty in regard to applying the MM5 to boiler DRE testing is analysis - compound identification and quantification. Currently gas chromatography is used with one of three detection modes MS, ECD, and FID. Each has its own benefits and disadvantages relating to sensitivity, reproducibility, compound identification, interference rejection, and analytical cost. Each of these factors needs to be considered and the method written to describe when each would be appropriate.

QA/QC Evaluation

Most of the QA emphasis has been on obtaining acceptable blank values and preventing contamination. The large gas sample and relatively large quantity of resin concentrate the sample which, in conjunction with the solvent extraction, usually results in a greater analyzable mass than methods employing a lower sample volume. This greater analytical mass tends to decrease the importance of trace contamination of the sample. The resin cleaning, blank extraction, field trip, and laboratory handling blanks are adequate to identify problems and likely causes.

There is one important aspect lacking in the method as it is being used and this is use of field spikes to check on sample loss and recovery efficiency. As currently practiced, the procedures does not provide a means for determining target compound collection efficiency or for evaluating sample recovery. The nature of the sample and the field conditions preclude the usual option of splitting the collected sample and spiking one split with a target compound to check loss and recovery. These spikes and replicate analyses can be performed in the lab using the extractate with some loss of sensitivity. It is also possible, and it seems highly advisable, to spike the field samples with a tracer compound having properties similar to the target compounds.

Because the volume of gas sampled by MM5 is large, the total quantities of the various semi-volatile organic compounds (S-VOC) in the samples ranged from a few to several hundred micrograms. Thus the MM5 results are not greatly influenced by even a few hundred nanograms of contaminants.

Two quality assurance acceptance criteria were applied to the MM5 data before they were included in this document.

1. The recovery of surrogate or spike compounds added to the sample before analysis must have been in the range of 50 to 150%.

2. The rate of feed of any given compound must have been 10,000 times the minimum detectable limit of the MM5 procedure.

The first of these is merely a demonstration of acceptable analytical accuracy. The acceptable range is wide relative to normally attainable analytical precision. It is adequate for this analysis because the DRE calculation is insensitive to an error of a factor of three (3) in the emission rate measurement.

The calculation of DRE, the primary use of the data in this document, is based upon the concentration of the various constituents in the waste feed stream and in the exhaust gas. The accuracy and precision of these concentration measurements decrease when they are near the limit of detection of the analysis methods. Consequently, the dispersion of DRE values that are calculated based upon these imprecise measurements becomes unacceptably large. The decision was made to include only those data that are as accurate as is possible using the available methods. The method chosen, the second of the quality assurance acceptance criteria, accomplishes this goal.

The blank MM5 samples were, for the most part, uncontaminated. The samples contained many times more of each compound of interest than the blanks. Correction of the sample values by subtraction of the blank values would have had little effect on most of the results. Therefore, the decision was made that no blank corrections would be done for the MM5 data.

At most sites a baseline run was performed. This consisted of the taking of a MM5 sample while the boiler was burning only virgin fuel. In many cases the emission rates of waste fuel constituents measured during the baseline run was of the same order of magnitude as their emission rate during the co-fired runs. No satisfactory explanation could be found for these observations. The baseline emission rates were not subtracted from the co-fired emission rates before calculation of DRE values. Although a case could be made for making the subtraction, it was decided to take the conservative approach and to err on the side of safety.

Volatile Organic Sampling Train (VOST) and Mini-VOST

Description of Method

The basic details of construction and operation of the VOST are described in the "Protocol for Collection and Analysis of Volatile POHCs Using a Volatile Organic Sampling Train (VOST)" by Envirodyne Engineers for IERL (Reference 1). The highlights of the procedure are described below. Stack gas is drawn through quartz wool particle filter in a glass or quartz probe heated to approximately 130°C, through a three-way stopcock and through a coil condenser. Following the condenser, the sample gas passes through a glass tube containing 1.6 g of Tenax®-GC, a condensate trap, a second condenser, and a second sorbent tube containing 1.0 g Tenax®-GC followed by 1.0 g of activated charcoal. A second condensate trap is next, followed by a silica gel drying tube, and the pump/flow control system (sample lines, valves, flow meters, gas meters, etc.). All portions of the sample line preceding the last condenser are glass, stainless steel, or Teflon®. Figure 4.2 is a schematic depiction of the train. Previous experiments have established 20 liters as a maximum safe sample volume for this train. A greater sample volume incurs the risk of stripping sorbed POHCs off the resin. The sample rate for these tests was 0.5 L/min for a total of 40 minutes per pair of tubes.

An ice water bath is used to circulate water through both condensers to maintain sample gas temperature below 20°C through the sorbent tubes. Temperature of the probe liner, first condenser outlet, ambient air, and dry gas meter are measured and recorded. Leak checks of the whole train and each pair of sorbent tubes for each run are conducted and the resulting vacuum is released by allowing ambient air in through a charcoal filter connected to the three-way valve.

Tubes used for the boiler tests were of the inside-inside design that are held in the sample train with stainless steel Swagelok® fittings and ceramic-filled Teflon® ferrules. Other samplers have used the inside-outside design; a double walled sorbent cartridge/shipping container that uses O-rings and end caps to seal the cartridges. Stainless caps are used to seal tube ends for shipment before and after sample collection. After sample collection, tubes are kept and shipped in chilled styrofoam containers.

The tubes were analyzed on a GC/MS using thermal desorption with trap and purge. The method is described in the protocol and involves spiking each tube or pair of tubes with an internal standard, thermally desorbing the tubes into a water trap, and purging the water trap onto an analytical column for component separation. Identification and quantification are made by elution times, characteristic ions, and ion current profile using a computerized data library.

The Mini-VOST method is an adaptation of the VOST protocol for short sampling times and field analysis. The sample itself is similar to the VOST procedure described in the previous paragraphs, except the second condenser and backup sorbent cartridge are eliminated. Also, a knockout was placed after the first condensor to collect condensate. A sample volume of 10 liters was used, which is one-half the VOST protocol volume. The sample was collected at a rate of 1.0 L/min for 10 minutes.

Standardization of Procedure

The VOST protocol provides clear and specific directions about the sample train to be used and the method of sampling and the method of analysis. Reagent preparation, sample handling, QA/QC activities, calibration and calculations are all described in detail. The protocol states that conditioned cartridges, as well as used ones with sorbed sample, be kept in ice water before use and after sample collection. This ice water storage is not required if acceptable blank levels can be maintained.

Options regarding sample collection and recovery (analysis) efficiencies are also provided along with evaluation criteria. The analytical procedure is also described very specifically.

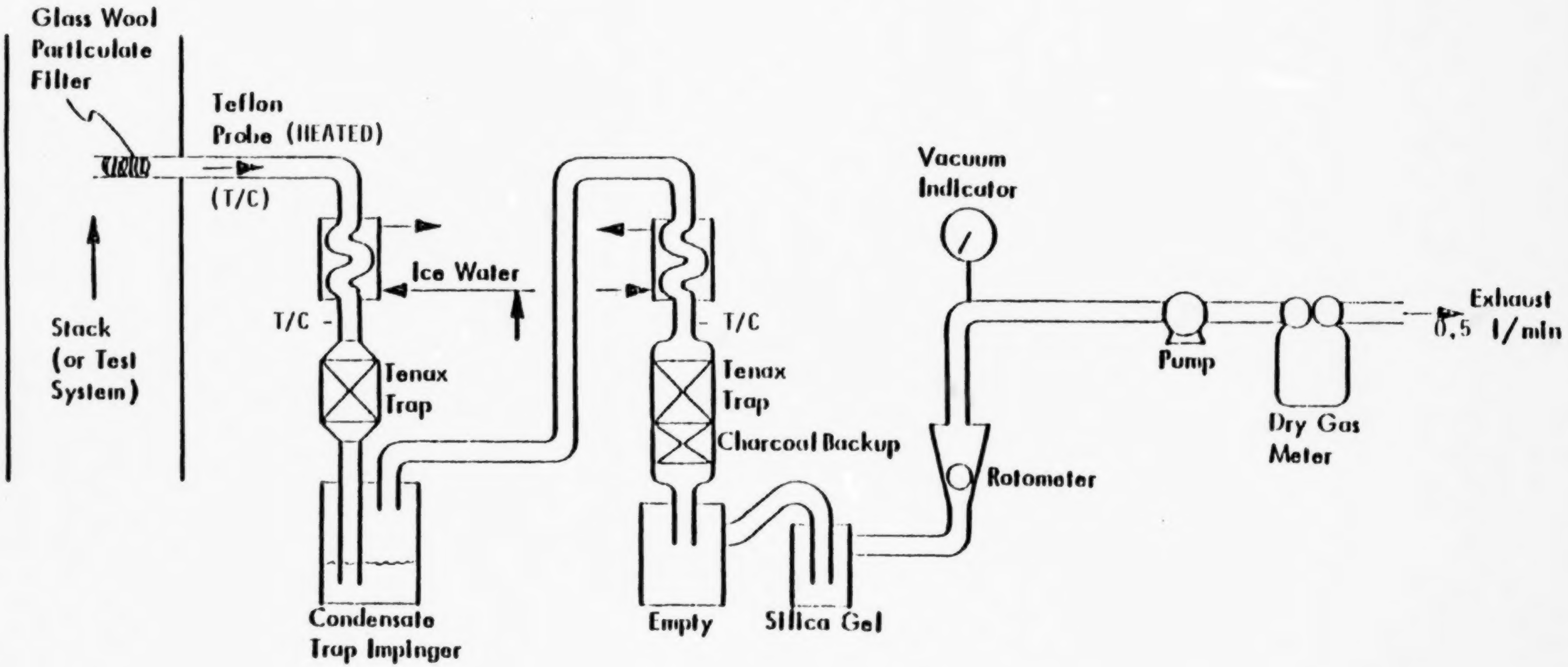

Glass Wool
Particulate
Filter
Teflon
Probe (HEATED)
(T/C)
Stack
(or Test
System)
Ice Water
T/C
Tenax
Trap
Condensate
Trap Impinger
T/C
Tenax
Trap
Charcoal Backup
Empty
Silica Gel
Vacuum
Indicator
Rotometer
Pump
Dry Gas
Meter
Exhaust
0.5 l/min

FIGURE 4.2

Volatile organic sampling train (VOST).

Mini-VOST procedures have not been standardized by EPA except for those steps that are identical to the VOST protocol. This procedure is still being evaluated by EPA.

QA/QC Evaluation

The following paragraphs describe the QA/QC criteria used in evaluating the VOST data. No criteria were established for the mini-VOST results which were accepted or reported as valid by the contractor performing the tests.

The pre-sampling QA activities are clear and direct. Tenax® and charcoal cleaning, tube packing, desorption blanking, provide sufficient assurance that the sample cartridges start clean. The trip blank, field blank, and lab blanks are intended to provide a history and background levels of contamination and/or degradation so that the results of the sample analysis reflect only POHCs present in the stack gas. This history is especially difficult to create if the samples and blanks are not analyzed promptly. Sample degradation, tube cross-contamination, contamination from external sources (lab air, ambient air, etc.), and calibration and response standard degradation become more likely and less distinguishable.

As each analysis is a one time occurrence (no way to split), if an analysis is bad, a tube contaminated or otherwise invalid, the data point is lost. As the sample collection involves three pairs, the duplication is inherent in the sampling. One could carry this suggestion further to say that two backups are desirable to yield an average value and increase the confidence in the results.

The protocol requires one exposure pair per six pairs of sample tubes. These exposure (field or shadow) blanks are opened as if they were sample tubes but are not installed in the train.

One QA action which has not been done, for several reasons, is spiking tubes in the field with one or more target POHCs or surrogates to establish recovery efficiencies. The difficulty stems from two major areas. One is the difficulty in maintaining reagent and tube purity in a field environment and the other is not being able to split a single sampling and spike one portion. The methods used to date have centered on lab simulations and the analytical process. A suitable field spike procedure would yield data on sample loss (leakage out) and desorption efficiency as well as additional data on contamination, lab QA, and overall method validity.

The following list identifies areas where additional effort and investigation could strengthen the VOST procedures.

- Spike blank cartridges in the field with a labeled compound to detect potential leakage during field storage and subsequent transport.
- Analyze the sample immediately with as little storage time in field and lab as possible.
- Conduct a detailed systematic evaluation of field handling, field storage, shipping, and lab storage, to identify potential causes of

contamination and/or leakage. Develop guidelines to detect and prevent contamination and to leak check cartidges.

- Investigate the current seal design. Do temperature changes cause leakage? How can one be certain the tubes are perfectly sealed? How can overtightening/undertightening be prevented? Can a pressure/vacuum tight seal be obtained repeatedly on a large number of tubes with no failures?

- Investigate cross contamination. Place spiked samples and clean blanks in the same container, store one to two weeks, and analyze. Do the above with loose fittings or cracked tubes and observe for cross contamination. Place the samples and lab blanks with their double seal in an atmosphere containing trace amounts of methylene chloride or waste fuel vapors, store, and analyze.

Quality assurance acceptance criteria were developed for the volatile organic compound data produced during each test. These criteria could not be identical for all sites since the methods used differed. In all cases only those components of the waste listed in Appendix VIII (CFR 40 Part 261) were included in the DRE results; even though there may have been other organic constituents measured in the waste feed and stack exhaust streams.

For most of the test performed during this program, three pairs of tubes constitute a sample run, this run sample would also include one exposure blank pair and one unopened (trip blank) pair. It is noted that not all of the volatile organic compound sampling done during these tests were done by the VOST procedure as has been described. The train used to sample volatile organic compounds (VOC) at Site C consisted of two tubes of Tenax®-GC in series. Sites D and E were sampled with one Tenax®-GC and one Tenax®-GC/charcoal tube. No condenser or other sorbent temperature control was used at Site C. Impingers were inserted in the train upstream and downstream of the Tenax®-GC tube at Site D and E.

Site M was sampled by EPA Method 23. Samples were collected in inert plastic bags rather than on sorbents.

The volatile organic compound sampling trains used at Sites D and E varied from the VOST train in that an impinger (containing water) in an ice bath was inserted in the sample line ahead of the Tenax®-GC cartridge. A second impinger was placed between the Tenax®-GC and the Tenax®-GC/charcoal cartridge at Site D. Three quality assurance acceptance criteria were applied to these data. They were:

- The contents of both impingers must have been analyzed.
- Both sorbent tubes must have been analyzed.
- At least 70% of the total quantity of any compound found on the sorbent tubes must have been found on the first (Tenax®-GC) tube.

The first two (2) of these are completeness criteria. While analysis of the condensate is not normally a part of the VOST protocol, it is necessary in these instances because of the location and the temperature of the condensate trap. The volume of condensate obtained from a 20-liter sample of boiler stack gas is approximately 1.5 ml. Even though the compounds of interest (mostly chlorinated hydrocarbons) are normally considered to be insoluble in water they are miscible to a small but measurable extent. A compound soluble to 1 mg/liter is said to be insoluble yet that translates to 1500 ng/1.5 ml of condensate which is large relative to the analytical quantities of interest. The VOST train causes the condensate to be drawn through the resin bed. The resin should remove the compounds from the condensate. Since there was no contact between the condensate and the resin at these sites, it was necessary to analyze the condensate.

The third acceptance criteria was included to eliminate contaminated samples from the data. Persons who have sampled surrogate stack gases spiked with chlorinated hydrocarbons under controlled conditions have reported that at least 90% of these compounds are sorbed on the first resin trap. This is not true of highly volatile compounds, e.g., vinyl chloride, but it is for the compounds of interest in this document. Tenax®-GC has sufficient affinity for these compounds to remove them nearly quantitatively from the sample gas stream. The charcoal, used as a back-up sorbent in the second cartridge, has a much greater sorbent capacity and affinity for these compounds. Thus, if the cartridges are exposed to contaminants, the second tube should sorb them at a higher rate. Therefore, setting the acceptance criteria at 70% allows acceptance of some contamination but rejects grossly contaminated cartridges.

At the remaining sites (F, G, H, I, J, K, M, and N) the VOST train (Figure 4.2) was used. Acceptance criteria #1 is not applicable but the other two are.

The procedure employed herein for making blank corrections follows that suggested by the VOST protocol. The mean and standard deviation of the quantity of each compound of interest was found from all blank tubes (field, trip and laboratory) analyzed. If the quantity of a compound was greater than the average blank value by an amount equal to or greater than three (3) times the standard deviation of the blanks, then (and only then) the average blank volume was subtracted from the test run value.

The effects of application of these quality assurance criteria on the data are discussed for each test in the following pages.

TEST BURN RESULTS

The initial surveys that were performed during the early stages of development of this background information document (BID) revealed that adequate information about the destruction and removal efficiency of hazardous compounds by industrial boilers did not exist. EPA has also developed extensive data that reported the DRE (DRE includes both thermal destruction and removal by control devices) of hazardous compounds by incinerators. There are significant differences in the two processes. Incinerators typically hold their combustion gases in an oxidizing atmosphere at temperatures ranging from 1800 to 2500°F for times ranging from 2.0 to 3.0 sec. The combustion zone temperature in boilers is typically higher (2250 to 3000°F) but the retention time is typically less (approximately 0.5 sec). However, kinetic theory predicts that elementary reactions should be faster at the higher boiler temperature by a factor ranging from 4 up to 20,000, depending upon the activation energy of the particular reaction. This range has been confirmed by thermal destruction analytical system (TDAS) data for many common hazardous compounds. These data demonstrate that rates of destruction increase by factors that range from 17 to 12,000 when the temperature is raised from 1900 to 3100°F.

EPA undertook a series of tests to determine whether the destruction of hazardous materials by co-firing in industrial boilers is adequate to protect the environment. Beginning in March 1982, EPA performed tests at 12 industrial boilers that are representative of the range of boilers co-firing liquid hazardous wastes. The results of these tests are described in this section.

The sources that have been tested are characterized in Table 4.2. The boilers range in size from 1 to 32 kg steam/sec (8000 to 250,000 lb steam/hr). With the exception of the boiler at Site G they were standard industrial boilers that are representative of the various boiler types currently in use. The boiler tested at Site G was specially modified to burn hazardous compounds. The modifications consisted, primarily of rearrangement of internal baffling so as to maintain surface and gas temperatures favorable for destruction of hazardous compounds. The remaining boilers were industrial equipment that had been modified only to the extent of providing a means for injection of hazardous wastes.

Destruction and Removal Efficiencies of Principal Organic Compounds (POHCs)

The data from all test sites have been reviewed and subjected to the quality assurance acceptance criteria that were presented previously. The results at each site are presented individually. An overview of the implications of all of the data are summarized following the individual test discussions.

The data are summarized, by site, in Tables 4.3 through 4.30. Each table heading reiterates some of the source characterization data that were presented in the previous section. The compounds listed are those that were measured in the waste and that are named in Appendix VIII (Reference 1).

Site A

The boiler tested at Site A was an old coal stoker that is used to burn waste wood and waste creosote at a wood preserving plant. Waste wood chips and saw dust are transported to the boiler by a conveyor system. Waste creosote trickles onto the wood from a storage tank that is suspended above the conveyor. No means to measure either the wood waste or the creosote waste flow rate was available during the tests. The test team attempted to measure the creosote flow rate by recording the change in the liquid levels in the creosote storage tank. The tank was large, however, so the rate of change of the level was small (approximately 2 inches/hour) and the rate measurement was unreliable. More uncertainty was added by the observation that

TABLE 4.2

COMPLETED FIELD TESTS ON HAZARDOUS WASTE CO-FIRING

Site Designation	Boiler Type	Primary Fuel(s)	Waste Description	Emission Control Source	Sampling Protocol
A	Keeler CP 308-hp (10,000 lb/hr of steam) water tube boiler	Wood chips, bark, and sawdust	Creosote sludge containing chlorinated aromatics including pentachlorophenol and chlorinated dibenzo-dioxins	Multiclone for particulate collection	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Tenax® train for volatile organics -- Continuous monitors O_2, CO_2, CO, NO_x, and TUHC o Bottom ash o Cyclone collected ash o Ambient hydrocarbon levels
B	Cleaver-Brooks 250-hp (8,400 lb/hr of steam) fire tube boiler	Natural gas	Alkyd wastewater with paint resin containing toluene, xylenes, and several acids	None	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Tenax® train for volatile organics -- Continuous monitors O_2, CO_2, CO, NO_x, and TUHC
C	Babcock & Wilcox 29-kg/s (230,000 lb/hr of steam) multiburner water tube	Natural gas	Phenolic waste containing phenol, alkyl-benzenes, and long-chain aromatic and aliphatic hydrocarbons	None	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Tenax® train for volatile organics -- Continuous monitors O_2, CO_2, CO, NO_x, and TUHC o Ambient hydrocarbon levels

TABLE 4.2--Continued

Site Designation	Boiler Type	Primary Fuel(s)	Waste Description	Emission Control Source	Sampling Protocol
D	Babcock & Wilcox 11.4-kg/s (90,000 lb/hr of steam) multiburner water tube[a]	No. 6 oil	o Waste stream no. 1 -- Mixture of methanol, xylenes, and tetrachloroethylene o Waste stream no. 2 -- Mixture of toluene and bis(2-chloroethyl) ether	None[b]	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Tenax® train for volatile organics -- Modified EPA Method 6 for HCl emissions -- C_1 to C_6 hydrocarbons by gas chromatography -- Continuous monitors O_2, CO_2, CO, NO_x, and SO_2 o Fly ash
E	Combustion Engineering 13.9-kg/s (110,000 lb/hr of steam) single burner packaged water tube	No. 6 oil and natural gas	o Waste stream no. 1 -- Mixture of methyl methacrylate, methoxy butanone, methyl methoxy butanone, and fluxing oils o Waste stream no. 2 and waste stream no. 1 artificially spiked with: -- Carbon tetrachloride -- Chlorobenzene -- Trichloroethylene o Waste stream no. 3, mixture of toluene, and methyl methacrylate	None	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Tenax® train for volatile organics -- Modified EPA Method 6 for HCL emissions -- C_1 to C_6 hydrocarbons by gas chromatography -- Continuous monitors O_2, CO_2, CO, NO_x, and SO_2

TABLE 4.2--Continued

Site Designation	Boiler Type	Primary Fuel(s)	Waste Description	Emission Control Source	Sampling Protocol
F	Babcock & Wilcox 7.6-kg/s (60,000 lb/hr of steam) multiburner water tube[a]	No. 6 oil	o Purge thinner containing mixed methyl esters, butyl cellosolve acetate, aromatic hydrocarbons, aliphatic hydrocarbons o Spiked with chlorobenzene, trichloroethylene, and carbon tetrachloride	None	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Volatile organic sampling train for volatile organics -- Modified EPA Method 6 for HCl emissions -- Continuous monitors O_2, CO_2, CO, NO_x, and TUHC
G	Modified fire tube boiler 5.0-kg/s (40,000 lb/hr of steam or 1,200-hp); thermal hot recovery oxidizer (THROX)[c]	None - natural gas used only for startup	o Mixture of chlorinated hydrocarbons containing up to 55% by weight chlorine; major components: -- Bis(2-chloroisopropyl) ether -- Propylene trichloride -- Epichlorohydrin o Spiked with carbon tetrachloride	Two chloride recovery/removal water scrubber columns in series	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Volatile organic sampling train for volatile organics -- Modified EPA Method 6 for HCl emissions -- Continuous monitors O_2, CO_2, CO, NO_x, and TUHC o Makeup scrubber water -- Chloride o Scrubber discharges -- Chloride -- Volatile organics by purge and trap (EPA Method 624)

TABLE 4.2--Continued

Site Designation	Boiler Type	Primary Fuel(s)	Waste Description	Emission Control Source	Sampling Protocol
H	Combustion Engineering tangential NSPS coal-fired 31.5-kg/s (250,000 lb/hr of superheated steam) boiler	Pulverized bituminous coal	Crude methyl acetate; spiked with trichloroethane, carbon tetrachloride, and chlorobenzene	Cold side electrostatic precipitator	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Volatile organic sampling train for volatile organics -- Modified EPA Method 6 for HCl emissions -- Continuous monitors O_2, CO_2, CO, NO_x, and TUHC o Bottom ash and fly ash for nonvolatile organics
I	Foster Wheeler type AG252 bent tube boiler 7.8-kg/s (68,000 lb/hr) of steam	Fuel oil or gas	o Waste gas (mostly methane) o Steam stripper waste from aniline production spiked with chlorinated hydrocarbons	None	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Volatile organic sampling train for volatile organics -- Modified EPA Method 6 for HCl emissions -- Continuous monitors CO, CO_2, O_2, NO_x, and TUHC o Composite liquid waste samples

TABLE 4.2--Continued

Site Designation	Boiler Type	Primary Fuel(s)	Waste Description	Emission Control Source	Sampling Protocol
J	North American model 3200X fire tube boiler 1.06-kg/s (8,400 lb/hr) of steam	Natural gas and No. 6 oil	Blended for test 98% toluene spiked with carbon tetrachloride, chlorobenzene, and trichloroethylene	None	o Flue gas -- Modified EPA Method 5 for toluene and chlorobenzene -- VOST for carbon tetrachloride and trichloroethylene -- Modified EPA Method 6 for HCl emissions -- EPA Method 23 for all waste components -- Continuous monitors O_2, CO_2, CO, NO_x, and TUHC
K	Combustion Engineering VU-10 water tube 7.6 kg/s (60,000 lb/hr) of steam	Heavy and light fuel oils	o Waste solvent o Light oil spiked with chlorinated hydrocarbons	None	o Flue gas -- Modified EPA Method 5 for semi- & nonvolatile organics -- Volatile organic sampling train for volatile organics -- Modified EPA Method 6 for HCl emissions -- Continuous monitors CO, CO_2, O_2, NO_x, and TUHC o Composite liquid waste samples

TABLE 4.2--Continued

Site Designation	Boiler Type	Primary Fuel(s)	Waste Description	Emission Control Source	Sampling Protocol
L	Combustion Engineering 13.9 kg/s (110,000 lb/hr) of steam single burner packaged water tube	No. 6 oil and natural gas	Methyl methacrylate still bottoms spiked with carbon tetrachloride and chlorobenzene	None	o Flue gas -- Modified EPA Method 5 for semi-volatile PICs -- VOST for volatile POHCs and PICs -- Field analyzed Tenax® tubes for volatile POHCs and PICs -- Total organic chlorine by electrical conductivity detector -- Continuous monitors for O_2, CO_2, CO, TUHC, NO_x, SO_2, and smoke
M	Combustion Engineering 44.2 kg/s (350,000 lb/hr) of steam, multipile burners	Natural gas	o Waste stream No. 1 - butanol/propanol heavy ends spiked with carbon tetrachloride, chlorobenzene o Waste steam No. 2 -- process - waste gas contaming principally, CH_4, C_2H_6, C_2H_4, CO, H_2, and aldehydes	None	o Flue gas -- Modified EPA method 5 for semi-volatile PICs and HCl -- VOST with post test analysis for volatile POHCs and PICs -- Mini-vost with onsite analysis for volatile POHCs and PICs -- Continuous monitors O_2, CO_2, CO, NO_x, and TUHC o Waste oil -- Grab samples with post test ultimate and POHC analyses

[a] Boiler originally stoker coal-fired converted to oil burning.

[b] Some particulate collected by existing hopper cavities.

[c] Patented process for heat generation and chemical recovery of highly halogenated hydrocarbons.

TABLE 4.2--Continued

Site Designation	Boiler Type	Primary Fuel(s)	Waste Description	Emission Control Source	Sampling Protocol
N	Riley spreader-stoker coal-fired 19.0 kg/s (150,000 lb/hr of steam)	Coal	o Inorganic sludge consisting primarily of water (79.5%) and served inorganic elements o Spiked with trichloroethylene o Spiked with 1,2,4-trichlorobenzen, lead, and chromium o No. 2 fuel oil spiked with trichloroethylene o No. 2 fuel oil spiked with 1,2,4-trichlorobenzene o No. 2 fuel oil spiked with 1,2,4-trichlorobenzene, lead, and chromium	Mechanical collection and baghouse in series	o Flue gas -- Modified EPA Method 5 for particulate mass, trace metals, and semi-volatile organics -- Vost with posttest analysis for volatile POHCs and PICs -- Anderson impactor for particle size distribution and trace metal partitioning -- Mini-VOST with onsite analysis of volatile chlorinated organics -- EPA Method 5 for particulate matter -- Modified EPA Method 6 for HCl -- Continuous monitors O_2, CO_2 CO, NO_x, SO_2, and TUHC -- Coal for ultimate and proximate analyses and metal -- Waste fuel (sludge or No. 2 oil) for POHCs, metals, and chloride -- Baghouse ash for trace metals and semi-voltile -- Mechanical collection ash for trace metals and semi-voltile -- buttom ash for metals and semi-volatiles

TABLE 4.2--Continued

Site Designation	Boiler Type	Primary Fuel(s)	Waste Description	Emission Control Source	Sampling Protocol
O	Modified Combustion Engineering coal stoker 2.8-kg/s (22,000 lb/hr) steam	Natural gas and No. 6 oil	Alcoholic still bottoms with methanol, methyl acetate, and methyl chloroform	None	o Flue gas -- EPA Method 23 for waste components -- Continuous monitors CO_2, CO, O_2, and TUHC -- Modified EPA Method 6 for HCl emissions

the wood waste apparently was contaminated with creosote. This observation, made qualitatively by the test team members based upon the odor of the wood, was supported by the results of the gross calorific value analyses of the wood waste. These analyses, together with typical heating values for wood found in the literature, led to the conclusion that the wood waste may have contained 25% creosote by weight. The relatively high emission rates of phenol and naphthalene (Table 4.3) during the baseline run add credence to the supposition that the wood waste contained creosote. Unfortunately, it is not possible to verify that the wood was contaminated. Therefore, the DREs of the various components are based upon the reported creosote feed rates.

The boiler thermal efficiency as determined by the ASME heat loss method was only 63%. The carbon monoxide concentration in the flue gas (Table 4.16) averaged 1,200 ppm. These observations imply that the boiler did not maintain good combustion conditions.

All of the hazardous components of the waste stream had boiling points in excess of 100°C so all of the POHC emission rates were based upon MM5 test results. Table 4.3 gives the feed rates, emission rates, and DREs for the seven Appendix VIII compounds for which the data met the quality assurance acceptance criteria. The report included data for 12 compounds that are not listed in Appendix VII. The DREs of these compounds was approximately 99.99%. The data for two compounds, 2,4-dimethyl phenol, and 4-nitrophenol were omitted because their concentration in the feed was too low. The data for one compound, pentachlorophenol, were omitted because its spike recovery (33%) was outside of the QA acceptance range.

Less than 1% of industrial boilers burn wood waste (or bagasse or other hog fuels) so it is not representative of a large number of boilers. Its operation (high CO, low efficiency) was not representative of good boiler combustion. The rate of feed of hazardous materials was not well documented; it probably was under-estimated by more than a factor of two. The DREs were marginally acceptable. This boiler may be operating just outside of the range of combustion conditions that provide adequate DRE of hazardous material. It, and others similar to it, seems to have the potential to destroy hazardous material but a trial burn demonstration of that potential should be required in individual cases.

Site B

The boiler at Site B was a gas-fired fire-tube in which alkyd resin waste was co-fired. The waste stream was largely water. The waste holding tank was nearly full during the tests so that the agitator could not be turned on without causing it to overflow. The lack of mixing allowed the organic material to separate and float to the top. Since the waste feed line was below the phase boundary the waste fed during the tests was more than 99.7% water. It is interesting to note that the water, which was 14% of the mass of the natural gas (Table 4.4), had no obvious deleterious effect on the boiler combustion. Neither the CO nor the total unburned hydrocarbon concentrations in the flue gas increased over their concentrations during the baseline run when the wastewater was co-fired. The test data do not allow

TABLE 4.3

SITE A

Manufacturer: Keeler CP
Type: Water Wall (solid fuel)
Fuel: Wood Waste
Waste Stream: Creosote Waste

Design Steam Rate: 10,000 lb/hr
Design Steam Pressure: 250 psig
Test Steam Rate: 10,000 lb/hr
Fraction Waste Fuel
Mass: 17%
Heat Input: 40%

		Quantity Found (ug)					
Compound	Feed Rate mg/sec	Base-line Run	Aver-age Blank	Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Cor-rected	DRE
phenol	44.7	350	ND	11	80	No	99.821
2,4-dinitrotoluene	13.0	ND	ND	ND	<0.6	No	>99.995
2,6-dinitrotoluene	21.7	ND	ND		<0.7	No	99.997
naphthalene	507	39	23	165	90.5	No	99.982
fluorene	283	ND	ND	23	<22.3	No	99.992
chrysene	40	ND	ND	29	3.0	No	99.993
bis(2-chloroethoxyl) methane	8	ND	ND	ND	<0.6	No	>99.994
mass-weighted average							99.978

NOTES: 1) $$\text{DRE} = \frac{\text{(Feed Rate)} - \text{(Test Emission Rate)}}{\text{Feed Rate}} \times 100\%$$

2) Waste feed rates were probably underestimated by approximately 125%. If the feed rates are increased by 125%, the mass-weighted DRE becomes 99.991.

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

TABLE 4.4

SITE B

Manufacturer:	Cleaver Brooks	Design Steam Rate:	8,400 lb/hr
Type:	Firetube	Design Steam Pressure:	150 psig
Fuel:	Gas	Test Steam Rate:	2,000 lb/hr
Waste Stream:	Paint Manufacturing Waste	Fraction Waste Fuel	
		Mass:	14%
		Heat Input:	<1%

		Quantity Found (ug)			Test		
Compound	Feed Rate mg/sec	Baseline Run	Average Blank	Test Runs (avg)	Emission Rate (ug/sec)	Blank[a] Corrected	DRE
naphthalene	0.0187	WASTE FEED RATES ARE TOO LOW TO					
pentachlorophenol	0.0065	ALLOW CALCULATION OF ACCURATE					
toluene	4.670	DESTRUCTION AND REMOVAL EFFICIENCIES					

NOTE: $$\text{DRE} = \frac{(\text{Feed Rate}) - (\text{Test Emission Rate})}{\text{Feed Rate}} \times 100\%$$

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

a conclusion as to the DRE of hazardous compounds to be made. The rate of feed of the hazardous compounds was insufficient to contribute measurable stack gas concentrations of the compounds of interest. The results re-affirm the need to assure that POHC feed rates are high enough that the residue (after 99.99% DRE) will exceed the limit of detection of the method to be used for their measurement in the stack gas.

Site C

The boiler tested at Site C was a wall-fired steam generator with a capacity of 230,000 pounds of superheated (250 psig) steam per hour. The boiler has six burners each having a gas ring and an oil gun. The oil guns were used to inject liquid waste while either natural or waste process gas is fired through the gas rings. The boiler operated well during the tests. There were no upsets reported. The boiler was operated at approximately 25% of its design capacity so the percent excess air was high during all tests. The concentrations of CO, NO_x, and unburned hydrocarbons were low.

Only two compounds listed in Appendix VIII were found in the waste feed and exhaust gas. The waste stream contained approximately 5% phenol and approximately 0.004% bis(2-ethylhexyl)phthalate. The DRE of phenol (Table 4.5) was in excess of 99.99%. The DRE of the phthalate was less than 98%. The phthalate was detected in all four of the stack gas samples. Its measured emission rate during the baseline run was twice its average co-fired emission rate, whereas the baseline emission rate of phenol was only 3% of its average co-fired emission rate. It appears that all of the phthalate measurements may have been due to contamination. Further evidence that the phthalate result was anomolous is provided by the non-Appendix VIII compound results. The DRE of nine other compounds identified in the waste feed averaged 99.999%, the same as the DRE of phenol. It is scarcely conceivable that one compound was not destroyed while 10 others were.

The conclusion is that a wall-fired boiler, operating at 25% of its design capacity with 40% of the fuel heat provided by waste, destroyed more than 99.99% of the hazardous organic material that was co-fired.

Site D

The boiler tested at Site D was a balanced draft, field erected watertube with a rated capacity of 90,000 pounds per hour of 260 psig saturated steam. The boiler was operated at approximately 80% of full load with (on the average) 40% of the heat provided by waste material and 60% by No. 6 fuel oil. The boiler has four B&W oil/gas burners. One of these was used to inject the waste material during the co-fired runs. The plant produces several different waste streams. Two were selected for testing based upon their relatively high contents of chlorinated hydrocarbons. One of these streams was primarily (approximately 70%) methanol with 15% xylene and 5% perchloroethylene (perc). The second was 90% toluene with 6-7% bis(2-chloroethyl)ether (BCEE). Three co-fired test runs were done for each waste stream.

TABLE 4.5

SITE C

Manufacturer:	Babcock & Wilcox	Design Steam Rate:	230,000 lb/hr
Type:	Wall Fired	Design Steam Pressure:	250 psig
Fuel:	Gas	Test Steam Rate:	59,000 lb/hr
Waste Stream:	Phenolic Wastes	Fraction Waste Fuel	
		Mass:	48%
		Heat Input:	38%

		Quantity Found (ug)					
Compound	Feed Rate mg/sec	Base-line Run	Aver-age Blank	Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Cor-rected	DRE
phenol	13,300	27	7	49	83	No	99.999
bis(2-ethylhexyl) phthalate	11	270	42	154	233	No	97.882
mass-weighted DRE							99.999

NOTE: $$\text{DRE} = \frac{(\text{Feed Rate}) - (\text{Test Emission Rate})}{\text{Feed Rate}} \times 100\%$$

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

Some upset conditions occurred during the field tests. These were mostly during the first co-fired run for the first waste stream. These upsets, which included smoke formation were caused by flame outs of the waste fuel burner which in turn were caused by waste feed disruptions and improper flame scanner settings. Testing was suspended during most of the upsets, though some testing did occur during upset conditions.

Perc and toluene were sampled by a variation of the VOST procedure. The train used included two impingers, one upstream and one downstream of the first sorbent cartridge. Considerable difficulty was encountered during the laboratory analysis of the Tenax®-GC samples. None of the impingers were analyzed for toluene and only 15 of the 21 were analyzed for perc. None of the seven impinger blanks were analyzed for either compound. These data were rejected because of their failure to satisfy quality assurance acceptance criteria #1. Both sorbent cartridges were analyzed for toluene in 6 of the 21 pairs and in only three of these cases was more than 70% of the sorbent-bound toluene found on the first cartirdge. Only one of seven pairs of sorbent cartridge blanks was analyzed for toluene. Both tubes of 9 of the 21 pairs of cartridges were analyzed for perc. Twelve pair did not satisfy quality assurance acceptance criteria #2. More than 70% of the sorbent-bound perc was on the first tube in only two of these nine pairs. Thus, only two runs satisifed all three quality assurance acceptance criteria. Only four of the seven sorbent blanks were analyzed. The amounts of these two compounds detected during runs when they were a fuel constituent was not significantly different from the amounts detected during runs when they were not.

All of this is strong evidence that the perc and toluene detected in the sampling train was the result of contamination. Even so, the calculated DRE for both compounds exceeded 99.99%. However, not enough data satisfied the quality assurance acceptance criteria to provide confidence in these numbers. Therefore, for the purpose of this document only the BCEE results (obtained by MM5) will be considered. These results (Table 4.6) show that the DRE of BCEE was much greater than 99.99%.

It is concluded that this boiler destroyed more than 99.99% of the hazardous compounds that were co-fired. Test runs 2, 3, and 6 were those during which most of the upset conditions occurred. Sampling during upset conditions was most prevalent during run 2. No effect on the emission rates or DREs of either hazardous or other compounds is evident in any of the data. These upsets apparently did not interfere with the destruction of the hazardous materials.

Site E

The boiler tested at Site E was a forced draft packaged water-tube with a design capacity of 110,000 pounds of superheated steam per hour. The design steam delivery pressure was 425 psig. The boiler is equipped with a dual air register COEN burner that has a gas ring and a No. 6 oil gun. This burner had been modified by the addition of two waste fuel guns. These were located at opposite ends of a diameter of the burner approximately midway between the oil gun and the gas ring.

TABLE 4.6

SITE D

Manufacturer:	Babcock & Wilcox	Design Steam Rate:	90,000 lb/hr
Type:	Water Wall (field erected)	Design Steam Pressure:	260 psig
Fuel:	Oil	Test Steam Rate:	70,000 lb/hr
Waste Stream:	Methanol and Toluene Wastes	Fraction Waste Fuel	
		Mass:	40%
		Heat Input:	37%

Compound	Feed Rate mg/sec	Quantity Found (ug) Base-line Run	Quantity Found (ug) Aver-age Blank	Quantity Found (ug) Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Cor-rected	DRE
bis (2-chloro-ethyl) ether	7,600	ND	ND	3.7	<4.7	No	>99.9999

NOTE:

$$DRE = \frac{(\text{Feed Rate}) - (\text{Test Emission Rate})}{\text{Feed Rate}} \times 100\%$$

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

Two different waste streams were co-fired during the tests. One (TSB waste) consisted largely (approximately 80%) of fluxing oils and contained approximately 1% methyl methacrylate (MMA) and 7% and 11% of x-hydroxy-methylisobutyrate (MOB) and x-hydroxy-methylisobutyrate methyl ether (MEMOB), respectively. The second (toluene waste) waste stream was approximately 80% toluene and 20% methyl methacrylate. A third waste stream (Cl-TSB) was prepared by adding approximately 2% each of carbon tetrachloride, chlorobenzene, and trichloroethylene to the TSB waste.

Nine test runs were done, they were:

o 1 baseline run - No. 6 oil only
o 1 co-fired, No. 6 oil plus TSB waste
o 5 co-fired, No. 6 oil plus Cl-TSB waste
o 1 co-fired, natural gas plus Cl-TSB waste
o 1 co-fired, natural gas plus toluene waste

Of the five co-fired (No. 6 plus Cl-TSB) runs, three were at 50% design steam load, one was at 37% load, and one was at 73% load. One of the gas-fired runs was at 50% load the other was at 40% load.

MMA, MOB, and MEMOB were all sampled and analyzed by MM5, the chlorinated hydrocarbons were sampled and analyzed by a modified VOST procedure. The modification consisted of placement of an empty impinger (in an ice bath) upstream of the first Tenax®-GC sorbent tube.

The Tenax®-GC sampling and analysis for the volatile hydrocarbons was only marginally successful. Of the total of 27 pairs of tubes exposed, the quality assurance acceptance criteria (QAAC) were satisfied for: carbon tetrachloride - 6 pairs, trichloroethylene - 3 pairs, chlorobenzene - 5 pairs, and MMA - 13 pairs. The number of analyses rejected by the various QAAC are shown below:

	Number of Samples Rejected for QAAC Failures			
Compound	QAAC #1 (impinger analysis)	QAAC #2 (analyze both tubes)	QAAC #3 (70% on first tube)	Accepted Samples
CCl_4	0	5	16	6
TCE	0	5	19	3
chlorobenzene	0	5	17	5
MMA	0	5	9	13

Based on the data that satisfied the QAAC, the average DREs for these compounds for all tests were:

	Test Average DRE	
Compound	QAAC Data	DRE All Data
carbon tetrachloride	99.9988	99.9996
trichloroethylene	99.9969	99.9986
chlorobenzene	99.9957	99.9981
methyl methacrylate	99.9887	99.9910

The third column, DRE calculations based upon all data, is similar to the second. Even though most of the measurements appear to be the result of contamination rather than compounds sampled from the flue gas, the DREs are all in excess of 99.99%. Such a conclusion cannot be unequivacable because there is a second possible explanation for the observation of large quantities of the compounds on the back-up sorbent tube, i.e., breakthrough. If the sampling train conditions were such that the first sorbent tube did not collect compounds efficiently, then finding large quantities of material on the back-up tube is expected. Determination of how much material may have broken through the back-up sorbent tube cannot be done quantitatively. It is unlikely that breakthrough caused high loadings on the back-up tube, but the possibility cannot be totally discounted. Therefore, the data can be accepted only with qualification. Only the DRE for methyl methacrylate is listed in Table 4.7 because it was the only compound for which there were enough successful test runs to afford confidence to a conclusion. The DRE of this compound appears to have been almost exactly 99.99%.

The two non-Appendix VIII compounds (MOB and MEMOB) that were present in the TSB waste in significant quantities were sampled by MM5 during these tests. The XAD-resin was maintained at 60°C during the sampling. At this resin temperature and the total volumes of gas sampled, the resin would have retained only 1/3 to 1/2 of these compounds. If the measured emission rates of these compounds are tripled the poorest calculated DRE becomes 99.996%.

The data from Site E are not sufficiently sound to allow definitive correlations between DRE and operating conditions to be made.

Site F

The boiler tested at Site F was a balanced draft water-tube with a rated capacity of 60,000 pounds per hour of 200 psig steam. The boiler was originally constructed to burn coal, but had been converted by the addition of two B&W circular burners to the burning of either oil (No. 6 or No. 2) or gas fuels. Waste solvent is injected through a separate y-jet gun near the center of the lower burner. The waste solvent normally co-fired in this boiler consists of paint thinner that has been used to purge paint spray guns. The waste was spiked with trichloroethylene, carbon tetrachloride, and chlorobenzene for the purposes of these tests. Waste thinner was 12% of the mass of fuel fed and provided 9% of the heat input.

The boiler had been out of service for repair of refractory before the test program. It had been operated solely on gas fuel since the repair at the time the tests began. Apparently, the lower oil gun had not been reinstalled properly after the repair. It became encrusted with coked fuel to the extent that is caused the boiler to shut down after the third test and again near the end of the fourth test. The burner misalignment had no observable effect upon the concentrations of any of the continuously monitored gases. Neither the carbon monoxide nor the total unburned hydrocarbon instruments were on-line during Test 4, so no data for these two gases at the time of failure are available. There were no significant changes in the concentrations of any of the combustion gases from test to test. The fraction of the particle emissions that was attributable to fuel ash dropped somewhat during Test 4. Between 92 and 106% of the stack gas solids were accounted

TABLE 4.7

SITE E

Manufacturer:	Combustion Engineering	Design Steam Rate:	110,000 lb/hr
Type:	Water Wall (package)	Design Steam Pres.:	425 psig
Fuel:	Oil	Test Steam Rate:	55,000 lb/hr
Waste Stream:	Methyl methacrylate manufacturing waste	Fraction Waste Fuel	
		Mass:	28-75%
		Heat Input:	21-52%

		Quantity Found (ug)					
Compound	Feed Rate mg/sec	Baseline Run	Average Blank	Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Corrected	DRE
methylmethacrylate	12,210	1.5	0.287	2.920	1378	Yes	99.989

NOTE: 1) $\text{DRE} = \frac{(\text{Feed Rate}) - (\text{Test Emission Rate})}{\text{Feed Rate}} \times 100\%$

2) Low DRE may be the result of sample contamination; see text.

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

for by fuel ash during the baseline and the first two co-fired runs. This fraction dropped to 80% during the final co-fired run (Test 4). This implies that the poor burner alignment was producing soot particles during Test 4 and was probably causing poor combustion efficiency.

Stack gas samples were taken by both VOST and MM5. Butylbenzyl phthalate was the only semi-volatile organic compound listed in Appendix VIII that was found in the waste stream. Its concentration in the thinner was approximately 2.5%. Its mass flow rate was approximately 0.85 gm/sec. It was not detected in any of the stack gas samples. Therefore, its DRE was in excess of 99.999%. The only other MM5 compound detected in both the thinner and any stack gas sample was butane dioic acid dimethyl ester. It was detected in the stack gas only during Test 3. Its DRE during that test was greater than 99.999%. Several other Appendix VIII compounds were detected in some stack gas samples. Of these only bis(2-ethylhexyl)phthalate was detected at levels significantly greater than its minimum detectable limits. The amount of this compound detected in the blank exceeded the average amount detected in the co-fired run samples so its detection is judged to be due to contamination.

The chlorinated hydrocarbons (carbon tetrachloride, trichloroethylene, and chlorobenzene) that were added to the thinner were sampled by the VOST procedure. Three pairs of VOST cartridges were used during each of the first two and two pairs during the third co-fired test runs. Of these eight pairs the QAAC were met by three carbon tetrachloride samples, three trichloroethylene samples, and three chlorobenzene samples. Two runs were rejected because of failure to analyze both tubes (QAAC #2). One analysis was lost because of failure of the GC/MS. Two analyses were rejected because the amounts of compounds found on the first tube was less than 70% of the total (QAAC #3). The DRE of only chlorobenzene appears to have been less than 99.99%. Its concentration in the thinner was low, only 20% of the planned concentration, however. Because the feed rate was so low the DRE calculation is subject to undue influence by small amounts of sample contamination. The DREs of the other two compounds (Table 4.8), both of which are more refractory than chlorobenzene, were greater than 99.99% as was the mass weighted average DRE.

Most (5 of 9) of the accepted data were from Test 4, the final co-fired run. It was during this run that the boiler was shut down by coking of the lower oil burner. The mass weighted DRE of all the chlorinated hydrocarbons during this test was 99.997%. It is difficult to compare this run to the other two co-fired runs since the data recovery from them was poor. The final co-fired run does demonstrate acceptable DRE under less than ideal operating conditions, however.

Site G

The boiler at Site G was a three-pass wetback scotch marine packaged fire-tube with design capacity of 26 million Btu/hr heat input. This boiler was originally rated at 40 million Btu/hr heat input but was derated in conjunction with its modification to a hazardous waste combustor. The modifications included a change from positive to negative pressure in the firebox and changes in internal baffle configurations needed to maintain surface temperatures that retard acid gas attack. The boiler is fitted with a two-stage

TABLE 4.8

SITE F

Manufacturer:	Babcock & Wilcox	Design Steam Rate:	60,000 lb/hr
Type:	Water Wall	Design Steam Pressure:	250 psig
Fuel:	Oil	Test Steam Rate:	50,000 lb/hr
Waste Stream:	Paint Solvents	Fraction Waste Fuel	
		Mass:	12%
		Heat Input:	9%

Compound	Feed Rate mg/sec	Quantity Found (ug) Base-line Run	Quantity Found (ug) Aver-age Blank	Quantity Found (ug) Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Cor-rected	DRE
trichloroethylene	1,100	0.398	0.041	0.104	25.7	Yes	99.998
chlorobenzene	109	0.029	0.010	0.060	15.3	Yes	99.986
carbon tetrachloride	806	0.116	0.107	0.264	70.3	Yes	99.991
mass-weighted DRE							99.992

NOTE:

$$\text{DRE} = \frac{\text{(Feed Rate) - (Test Emission Rate)}}{\text{Feed Rate}} \times 100\%$$

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

scrubber system to remove and recover halogen acids from the exhaust gases. The boiler was equipped to burn natural gas and either liquid or gaseous wastes. It would operate on waste halogenated hydrocarbons only, if the heat value of the waste exceeds 9,500 Btu/lb.

The waste being fired during the tests contained 40% bis(2-chloroisopropyl)ether (BCPE), 30% propylene dichloride, and 17% epichlorohydrin. Four percent carbon tetrachloride (CCl_4) was added to the waste for the purpose of the tests. The waste was approximately 43% chlorine. Its average heating value was 8,990 Btu/lb, slightly less than the heat value specified by the manufacturer for waste only firing. In spite of the nature of the fuel, the boiler operated with out incident at 82-83% thermal efficiency while burning 100% waste throughout the tests.

Carbon monoxide (CO) and total unburned hydrocarbon (TUHC) concentrations decreased slightly during the tests. The average concentration of CO decreased from 170 ppm (all concentrations corrected to 3% O_2) during Test 1 to 146 ppm during Test 3; TUHC decreased from 0.7 ppm to 0.3 ppm. The changes, though small, were attributed to better atomization of the waste during the later runs.

One Appendix VIII compound (BCIE) was sampled and analyzed by MM5. It was detected in one of the three samples at an emission rate of 1.2 micrograms per second.

Three Appendix VIII compounds were sampled and analyzed by VOST procedure. They were: CCl_4, epichlorohydrin, and trans-1,3,dichloropropene (T-DCP). Epichlorohydrin was not detected in any stack gas sample. T-DCP was detected, in trace amounts, in two of the eight pairs of VOST tubes analyzed. CCl_4 was detected in all eight pairs of VOST tubes but three pairs did not satisfy QAAC #3 (less than 70% on first tube). Its emission rate averaged 259 micrograms per second, over half of which was observed during the first part of the second test. No measured aspect of the boiler operation accounts for this one high emission rate result.

All compounds were destroyed with greater than 99.99% efficiency (Table 4.9) during all test runs. This was a special purpose boiler. The results can be extrapolated to similar units designed for the purpose of destruction of hazardous materials.

Site H

The boiler tested at Site H was a pulverized coal-fired boiler built in 1975, with a rated steam capacity of 250,000 lb/hr of superheated steam at 600 psig and 740°F. This tangentially fired boiler was equipped with three levels of pulverized coal burners in each furnace corner. The three levels were separated by two levels of steam-atomized oil burners. Generally, organic wastes were injected into the furnace by means of one or more of these oil burners. Typical steam loads are 250,000 lb/hr which is the rated steam capacity of the boiler. Primary and secondary combustion air is preheated by means of a regenerative air preheater. The unit is equipped with a cold side ESP for fly ash control. Fly ash is collected and removed from the hopper continuously via pueumatic system.

TABLE 4.9

SITE G

Manufacturer:	THROX	Design Steam Rate:	26,000 lb/hr
Type:	Fire Tube	Design Steam Pressure:	250 psig
Fuel:	None	Test Steam Rate:	15,000 lb/hr
Waste Stream:	Chlorinated Solvents	Fraction Waste Fuel	
		Mass:	100%
		Heat Input:	100%

		Quantity Found (ug)					
Compound	Feed Rate mg/sec	Baseline Run	Average Blank	Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Corrected	DRE
carbon tetrachloride	9,800	NR	0.0143	2.58	259	Yes	99.997
trans-1,3-dichloropropene	31,600	NR	ND	0.003	<2.0	Yes	>99.9999
epichlorhydrin	40,400	NR	<1	<1	<2	Yes	99.9999
bis(2-chloroisopropyl)ether	107,000	NR	<1	<1	<2.0	No	>99.9999
mass-weighted average DRE							99.9997

NR - No baseline run at this site, the boiler burned only hazardous waste.

NOTE:

$$\text{DRE} = \frac{\text{(Feed Rate)} - \text{(Test Emission Rate)}}{\text{Feed Rate}} \times 100\%$$

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

Several organic waste streams are produced and incinerated in the boilers at this site. Firing rates of these waste streams are generally between 3 and 7 gpm when boiler loads exceed 150,000 lb/hr. The waste stream of interest was crude methyl acetate available in a 1,500-gal tank. The methyl acetate was artificially spiked with chlorinated organic compounds, namely CCl_4, chlorobenzene (Cl0), and 1,1,1-trichloroethane.

Four tests were performed: one baseline and three co-fire. All tests were performed with the boiler set on manual control. A heat output of 246,000 lb/hr of steam was maintained. No boiler upsets or transients were recorded. For Test 1, the boiler was operated with pulverized coal (generally eastern Kentucky or south West Virginia bituminous only). Furnace excess air and soot blowing cycles were typical for this firing condition. Tests 2 through 4 were the co-firing tests. The chlorinated methyl acetate firing rate varied from 2.4 to 4.2 gpm. One steam-atomized oil burner was used to input the waste which accounted for 2 to 4% of the total heat input to the boiler.

The minimum concentration of any POHC in the waste fuel was approximately 2%. At this concentration and at the rate of waste feed cited the minimum rate of flow of any POHC was approximately 2.5 g/sec. At 99.99% DRE the flow rate of this POHC in the flue gas would have been approximately 250 ug/s, which is easily detectable by the method of sampling and analysis used.

No test report is available for this site so it is not possible to compare the methods and data to the QA acceptance criteria that were developed earlier in this section. The data in Table 4.10 were abstracted from a report that summarized the results from all sites. The data available indicate that the boiler achieved 99.99% DRE of hazardous materials.

Site I

The boiler tested at Site I was a forced draft bent tube capable of delivering 62,000 pounds of 175 psig steam per hour. The boiler was originally designed for either oil or gas fuels but had been modified to burn waste gas (largely methane) in combination with small amounts of organic liquid waste. The boiler was equipped with two gas ring burners. Steam atomizing liquid waste guns could be inserted into the center of both. The burners are arranged in a vertical plane. Most of the organic liquid waste burned by the plant (and the only liquid waste burned during these tests) is a high nitrogen aniline production waste. The plant normally operates the boiler in a staged combustion mode while burning the high nitrogen waste in order to reduce formation of nitrogen oxides from fuel-bound nitrogen. Staging is accomplished by firing the high nitrogen waste through the lower burner and reducing the flow of combustion air through the burner port.

Approximately 2% each of carbon tetrachloride (CCl_4) and trichloroethylene (TCE), and 3.5% chlorobenzene (MCB) and toluene were added to the nitrogenous waste during the tests. The fuel, as fired, contained approximately 83% nitrobenzene (NB) and 2% each of anilane (AB) and benzene. The organic liquid waste contributed approximately 17% of the fuel mass and approximately 8% of the fuel-heat input. The primary fuel burned during the tests was natural gas.

TABLE 4.10

SITE H

Manufacturer:	Combustion Engineering	Design Steam Rate:	250,000 lb/hr
Type:	VU-40	Design Steam Pressure:	600 psig
Fuel:	Pulverized Coal	Test Steam Rate:	246,000 lb/hr
Waste Stream:	Methyl Acetate Waste	Fraction Waste Fuel	
		Mass:	6%
		Heat Input:	3%

		Quantity Found (ug)					
Compound	Feed Rate mg/sec[a]	Base-line Run[a]	Aver-age Blank[a]	Test Runs (avg)[a]	Test Emission Rate (ug/sec)[a]	Blank[b] Cor-rected[a]	DRE
carbon tetrachloride							99.98
chlorobenzene							99.992
methyl chloroform							99.994
mass-weighted average DRE							99.991

[a] Data not available

[b] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

Both MM5 and VOST samples were taken during the tests. The procedure used for each POHC is summarized below:

MM5	VOST
chlorobenzene	carbon tetrachloride
aniline	benzene
nitrobenzene	trichloroethylene
	toluene

Toluene would normally be sampled by MM5 since it boils at 111°C. However, since the VOST results for toluene were higher than the MM5 results they were used to calculate DREs for toluene. Both benzene and chlorobenzene (MCB) were also tested by both methods. The two methods gave comparable results for MCB. Benzene is too volatile to remain in the sample during the MM5 solvent evaporation. The test organization concluded that benzene was either a contaminant in or a product of decomposition of the Tenax®. Therefore, the benzene results were deemed unreliable and are not reported in Table 4.11.

All MM5 data met both quality QAAC that were developed for them.

The test method used for the VOCs was VOST so QAAC No. 1 (impinger analysis) does not apply. All VOST samples satisfied QAAC No. 2 (both tubes analyzed). All the VOST samples were analyzed in pairs, however - no individual analyses of the Tenax® or Tenax®/charcoal tubes were done. Therefore, QAAC No. 3 (70% on first tube) cannot be applied.

Combustion staging effectively reduced production of NO_x from fuel-bound nitrogen. Whereas 72% of the fuel bound nitrogen was oxidized to NO_x during the six unstaged combustion runs, only 22% was oxidized to NO_x during the staged combustion runs.

There was no difference in the exhaust gas concentrations or the DREs of any of the compounds between the staged and unstaged combustion runs. Of the compounds measured, only nitrobenzene and CCl_4 were emitted at a significantly (95% CI) higher rates during the co-fired tests than during the baseline tests. Therefore, the DRE data have been combined. The averages shown in Table 4.11 are for all six co-fired runs. The DRE of all compounds tested exceeded 99.99% for all co-fired test runs.

It is apparent that the combustion staging practiced at this site was effective at reducing the conversion of fuel-bound nitrogen to NO_x but that it had no adverse effect on the DRE of the co-fired hazardous compounds.

Site J

The boiler tested at Site J was a packaged, fire-tube capable of delivering 8,400 pounds of 150 psig steam per hour. It is designed to burn either oil or natural gas but normally burns the latter. The fuel burned during these tests was blended from nitration-grade toluene and technical grade chlorinated hydrocarbons. The fuel contained approximately 1% each of carbon tetrachloride and trichloroethylene and 0.5% chlorobenzene; the balance (97.5%) was toluene.

TABLE 4.11

SITE I

Manufacturer:	Foster Wheeler	Design Steam Rate:	68,000 lb/hr
Type:	Bent tube (staged combustion)	Design Steam Pressure:	250 psig
		Test Steam Rate:	40,000 lb/hr
Fuel:	Oil or Gas	Fraction Waste Fuel	
Waste Stream:	Aniline Wastes	Mass:	17%
		Heat Input:	8%

Compound	Feed Rate mg/sec	Quantity Found (ug) Base-line Run	Aver-age Blank	Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Cor-rected	DRE
carbon tetrachloride	797	0.061	0.028	0.133	24	Yes	99.997
trichloroethylene	797	0.019	0.043	0.026	8	No	99.999
chlorobenzene	1,457	0.209	0.0423	0.183	29	No	99.998
toluene	1,571	0.190	0.174	0.199	16	No	99.999
nitrobenzene	37,980	21.1		64.9	360	Yes	99.9998
aniline	1,070	10.6		12.93	21	Yes	99.998
mass-weighted average DRE							99.9989

NOTE:

$$\text{DRE} = \frac{(\text{Feed Rate}) - (\text{Test Emission Rate})}{\text{Feed Rate}} \times 100\%$$

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

The operation of the boiler was varied during the tests in an attempt to discover what effects boiler load and excess air have on the DRE of hazardous compounds. The operating conditions are summarized below:

Test Number	Condition	Steam Flow	Excess Air
1	1	Half Load	Normal
2	2	Full Load	Normal
3	1	Repeat of Test 1	
4	3	Full Load	High
5	4	Half Load	High
6	5	Full Load	Low

Two of the compounds, chlorobenzene, and toluene were measured by MM5. All of the toluene results satisfied both QAAC. The feed rate of chlorobenzene was insufficient to provide measurable concentrations in the stack gas at 99.99% DRE. Most (11 of 17) chlorobenzene results were less than detectable and the calculated DRE was 99.96%. The maximum calculable DRE, based upon the limit of detection and the feed rate, was 99.98%. It was judged that the data could neither confirm nor deny 99.99% DRE of chlorobenzene so it was not included in this analysis.

Carbon tetrachloride and trichloroethylene were sampled by VOST so QAAC No. 1 (impinger analysis) does not apply. Six of the 55 pairs of VOST tubes sampled were invalidated because one or the other tube was broken (QAAC No. 2) and therefore not analyzed. An additional 19 pairs were lost because of problems in the GC/MS. Six pairs of tubes were analyzed individually in order to indicate the fraction of the compounds collected on the first versus the backup tube. Unfortunately, three of these analyses were lost, either by GC/MS problems or broken tubes. The average fraction of the compounds of interest found on the first tube of the three remaining pair was 85%. Of the six analyses (three for CCl_4 and three for TCE) all showed more than 80% on the first tube but one. The first tube contained only 61% of the total collected TCE in one pair of tubes. Though the amount of data is small it was judged that QAAC No. 3 was satisfied by the data.

The DRE (Table 4.12) of every compound during every run exceeded 99.99%. The DREs of hazardous compounds at 50% load were no different from the DREs at full load. No change in the DRE was found when the excess combustion air was changed from a low of 17% to a high of 50%. The DREs measured at these extreme values of excess air were the same as those measured at the normal excess air of approximately 35%.

It is concluded that small fire-tube boilers can maintain adequate DRE of hazardous compounds while operating between 50-100% of full load. It is further concluded that the changes in excess air that occur when the load is changed do not reduce the DRE of hazardous compounds.

Site K

The boiler tested at Site K was a water-tube boiler that was designed to deliver 60,000 pounds of 125 psig steam per hour. It is equipped with four burners each of which can be used to fire either light or heavy oil by connecting the appropriate burner tip. Heavy oil is steam-atomized, light oil

TABLE 4.12

SITE J

Manufacturer:	North American	Design Steam Rate:	6,000 lb/hr
Type:	Fire Tube	Design Steam Pressure:	150 psig
Fuel:	None	Test Steam Rate:	full load
Waste Stream:	Blended (98% toluene)	Fraction Waste Fuel	
		Mass:	100%
		Heat Input:	100%

		Quantity Found (ug)					
Compound	Feed Rate mg/sec	Base-line Run	Aver-age Blank	Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Cor-rected	DRE
carbon tetrachloride	360	--	0.036	0.120	17.2	Yes	99.995
trichloroethylene	494	--	0.010	0.061	4.3	Yes	99.9991
toluene	44,050	--	140	877	1,514	No	99.997
mass-weighted average DRE							99.997

NOTE:

$$DRE = \frac{(\text{Feed Rate}) - (\text{Test Emission Rate})}{\text{Feed Rate}} \times 100\%$$

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

is air-atomized. The boiler typically burns off-specification fuels and waste solvents. The burners are located in a horizontal row along one side of the boiler. During the three baseline tests, standard No. 6 oil was fired through all four burners. During the three co-fired tests a mixture of 70% No. 6/30% waste solvent was fired through the two outside burners and a light oil (a waste solvent mixture) spiked with chlorinated hydrocarbons was fired through the two inside burners. The light oil contained approximately 0.5% each of carbon tetrachloride, trichloroethylene, and chlorobenzene. The waste oils also contained approximately 5% xylenes and approximately 1% benzene. Xylenes were not considered because they are not listed in Appendix VIII; benzene was not considered because its concentration in the waste feed is low (QAAC No. 2).

Only phenol was determined by MM5. Both QAAC were satisfied by all the phenol data. The VOST method was used to measure the concentrations of carbon tetrachloride, trichloroethylene, toluene, and chlorobenzene. QAAC No. 1 (impinger analysis) is not applicable. Five of the 24 pairs of VOST tube analyses were not accepted because of failure to analyze either the first tube or the back-up tube (QAAC No. 2). The laboratory attempted analysis of individual tubes for four pairs of VOST tubes. Two of these attempts failed because of loss of one or the other of the analyses. The average amount of the various POHCs found on the first tube of the two pairs for which separate analysis was successful was 93%. These analyses were taken as evidence that QAAC No. 3 (70% on first tube) was satisfied by all VOST analyses.

The boiler was operated at 80% capacity during these tests. The percent excess air was invariant at approximately 25%. Individual carbon monoxide concentrations ranged from 65-300 ppm. Test long averages ranged from 87-150 ppm. The waste material contributed 57% of the fuel mass and 49% of the heat input. Combustion efficiency (calculated from CO_2 and CO concentrations) averaged 99.9%. The DRE of all compounds (Table 4.13) exceeded 99.99% during all co-fired test runs. The lowest DRE measured (99.998%) was measured for carbon tetrachloride during Run 6.

Site L

The testing at Site L was undertaken as an attempt to define the range of boiler operating conditions over which adequate DRE of hazardous compounds can be attained. The boiler was controlled at the request of the test team to provide DRE tests under conditions of: low steam load, low O_2, high O_2, normal CO, high CO, rapid steam load changes, high fuel substitution rate, various waste atomizer steam pressures, different waste atomizer orientations, with No. 6 oil primary fuel and with natural gas primary fuel. Stack gas and boiler operating parameters were measured in an attempt to find relationships between them and poor DRE of hazardous compounds.

The boiler tested at Site L (Site L testing was done on the Site E boiler) was a forced draft packaged water-tube with a design capacity of 110,000 pounds of superheated steam per hour. The design steam delivery pressure was 425 psig. The boiler was equipped with a dual air register COEN burner that had a gas ring and a No. 6 oil gun. This burner had been modified by the addition of two waste-fuel guns. These were located at opposite ends of a diameter of the burner, approximately midway between the oil gun and the gas ring. The waste-fuel is normally atomized in a fan shaped pattern that impinges upon the oil flame but they can be rotated so that the waste fuel is sprayed away from the flame toward the boiler walls. The waste fuel was methyl methacrylate wastes spiked with carbon tetrachloride and chlorobenzene. During these tests the waste material supplied between 12 and 56% of the total heat input to the boiler. The ranges of conditions under which the boiler was operated during these tests, are compared to good engineering practice (Reference 22) below.

Range of Flue Gas Compositions for
Gas- and Oil-Fired Package Water-Tube Boilers

	Gas-Fired		Oil-Fired	
Flue Gas Component	Good Engineering Practice	These Tests	Good Engineering Practice	These Tests
O_2 (%)	2.5 to 5.5	2.2 to 5.3	3.0 to 7.6	3.5 to 6.3
NO_x (ppm)	70 to 100	a	65 to 470	a
CO_2 (%)	9.0 to 10.0	a	7.5 to 13.5	a
CO (ppm)	145 to 170	90 to 1970	45 to 55	90 to 370
TUHC (ppm)	25 to 45	a	3 to 35	a

[a] Data not available.

The data for the hazardous compound DRE runs, Table 4.14, demonstrate that with few exceptions the boiler destroyed more than 99.99% of both of the hazardous components. The DRE of carbon tetrachloride (CCl_4) was less than 99.99% in 3 of 44 runs; the DRE of chlorobenzene (ClPhi) in only 2. These 5 runs are summarized below.

Site L
Summary of Tests Showing DRE Less than 99.99%

		DRE				
Date	Time	CCl_4	ClPhi	CO (ppm)	O_2 (%)	Comment
May 8	1447	99.7	100.0	92	5.25	Low waste flow
May 8	1660	99.9996	99.98	345	4.7	No waste atomization
May 8	2232	99.998	99.97	120	4.3	Soot blowing
May 9	1311	99.987	99.995	325	3.07	Low waste flow, O_2
May 10	1030	99.989	99.993	128	6.33	Waste startup

Two of these are related to waste feed disruptions (one startup and one test with no atomization). Two occurrences of low DRE occurred during periods of low waste feed rate. These appeared to be caused by the relative instability of the waste feed rate control system at low waste flow rates. Although only two DREs at low waste flow were less than 99.99%, all DREs measured when the waste flow was less than 1.5 gallons per minute were relatively low.

TABLE 4.13

SITE K

Manufacturer:	North American	Design Steam Rate:	60,000 lb/hr
Type:	Fire Tube	Design Steam Pressure:	125 psig
Fuel:	No. 6 Oil	Test Steam Rate:	49,000 lb/hr
Waste Stream:	Alcohol, Waste Solvents	Fraction Waste Fuel	
		Mass:	51%
		Heat Input:	49%

Compound	Feed Rate mg/sec	Quantity Found (ug) Base-line Run	Aver-age Blank	Test Runs (avg)	Test Emission Rate (ug/sec)	Blank[a] Cor-rected	DRE
carbon tetrachloride	2,090	0.022	0.065	0.081	18.0	No	99.999
trichloroethylene	1,800	0.008	0.009	0.044	9.0	No	99.999
toluene	8,290	0.081	0.089	0.143	14.6	Yes	99.999
chlorobenzene	1,945	0.013	0.024	0.025	1.4	Yes	99.999
phenol	49,760	None		5	<370	No	>99.999
mass-weighted average DRE							99.999

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

TABLE 4.14

DRE GROUPED BY TEST CONDITIONS
SITE L

DATE	TIME	GC #	FUEL	LOAD	CONDITIONS	CCL4	CHLORO-BENZENE	MMA
25-Apr		MM5	GAS	59000	TSB BASELINE	NA	NA	99.9997
27-Apr		MM5	GAS	59000	TSB BASELINE	NA	NA	99.999987
10-May	1408	96	OIL	27000	LOW LOAD BASELINE	99.996	99.9996	
10-May	945	90	OIL	28000	LOW LOAD BASELINE	NA	NA	
10-May	716	87	OIL	32000	LOW LOAD BASELINE	NA	NA	
10-May	1647	101	OIL	44000	BASELINE OIL, MODERATE	99.9988	99.9997	
10-May	1750	103	OIL	46000	HIGH GPM/MODERATE LOAD	99.9996	99.9998	
10-May	1831	104	OIL	50000	MODERATE O2/HIGH GPM	99.99997	99.99993	
09-May	1410	67	GAS	52000	GAS BASELINE	99.998	99.9986	
08-May	1740	48	GAS	54000	LOW O2 BASELINE	99.9997	100	
27-Apr	1626	FULL VOST	GAS	57000	BASELINE	99.997	99.99991	99.99992
25-Apr	1732	FULL VOST	GAS	57500	TSB BASELINE	NA	NA	99.99989
08-May	1430	36	GAS	58000	TSB HIGH GPM BASE	99.9995	99.997	
25-Apr	1606	FULL VOST	GAS	58000	TSB BASELINE	NA	NA	99.99987
27-Apr	1755	FULL VOST	GAS	60000	BASELINE	100	99.99988	99.999897
08-May	1154	35	GAS	60000	TSB HIGH GPM BASE	99.99990	99.99991	
12-May	9	FULL VOST	OIL	60000	HIGH O2	99.99994	99.99988	99.9997
11-May	1528	144	OIL	60000	HIGH BASELINE	99.98	99.998	
11-May	2319	FULL VOST	OIL	61000	HIGH O2	99.9997	99.9998	99.9996
27-Apr	1446	FULL VOST	GAS	62000	BASELINE	99.996	99.99989	99.9998
25-Apr	1445	FULL VOST	GAS	64000	TSB BASELINE	NA	NA	99.9997
11-May	7	122	OIL	50000	MIN. USABLE ATOM	99.9997	99.99989	
10-May	2313	118	OIL	50000	MIN. USABLE ATOM	99.9998	99.998	
08-May	1600	40	GAS	57000	NO WASTE ATOMIZER	99.998	99.98	
11-May	2225	FULL VOST	OIL	60000	POOR ATOM	99.9998	99.9998	99.9997
11-May	2033	1 TRAP VO	OIL	60000	REDUCED ATOM.	99.99989	99.9997	99.9988
08-May	2224	FULL VOST	GAS	61000	LOW ATOM STEAM (VARY)	100	100	99.996
09-May	20	53	GAS	73000	EA TRANSIENTS	100	99.994	
09-May	2108	77	GAS	25000	GPM TRANSIENTS	99.9990	99.9994	
10-May	1030	92	OIL	28000	WASTE STARTUP	99.989	99.993	
10-May	1917	105	OIL	47000	GPM TRANSIENTS	99.9997	99.99989	
08-May	2108	FULL VOST	GAS	60000	WASTE OIL STARTUP	99.9997	99.997	99.9996
11-May	1430	143	OIL	62000	WASTE STARTUP	99.998	100	
10-May	2134	109	OIL	47000	INVERTED SPRAY	99.9990	99.99992	
10-May	2012	107	OIL	47000	START INVERTED SPRAY	99.9989	99.9998	
10-May	2055	108	OIL	50000	INVERTED SPRAY	99.9994	99.99994	
09-May	1508	69	GAS	25000	LOAD REDUCTION	99.997	99.9990	
09-May	2301	83	GAS	35000	LOAD DECREASE	99.9995	99.9997	
10-May	1452	97	OIL	40000	LOAD INCREASE	99.998	99.9996	
09-May	2153	81	GAS	55000	LOAD INCREASE	99.9997	99.99993	
09-May	921	57	GAS	63000	START UP DUAL VOST	99.99994	99.9994	
09-May	1702	FULL VOST	GAS	25000	LOW LOAD, MODERATE O2	99.9997	99.9997	99.9997
09-May	1946	76	GAS	27000	LOW LOAD/O2/GPM	99.998	99.998	
10-May	1132	94	OIL	27000	LOW LOAD/O2/GPM	99.994	99.995	
09-May	1801	74	GAS	28000	LOW LOAD, LOW O2	99.998	99.9989	
09-May	1311	66	GAS	51000	LOW O2 & GPM	99.987	99.995	
09-May	1142	62	GAS	53000	LOW O2 & GPM	99.999904	100	
08-May	1710	46	GAS	55000	LOW O2 WASTE INCREASE	100	99.9998	
09-May	1038	60	GAS	57000	LOW O2	99.9998	99.9989	
08-May	1642	42	GAS	59000	LOW GPM/O2	99.998	99.998	
08-May	1447	38	GAS	60000	LOW GPM	99.7	100	
11-May	2118	1 TRAP VO	OIL	60000	SOOTBLOW	100	99.9998	99.9995
10-May	2222	111	OIL	46000	SOOTBLOW	99.9993	99.9998	
08-May	2332	50	GAS	62000	SOOT BLOW	99.998	99.97	
09-May	2346	86	GAS	32000	SOOTBLOW LOW LOAD	99.9996	99.9998	

Low steam production did not reduce DRE. Between 1508 and 2018 on May 9, the boiler operated at approximately 24% capacity. DREs during this time average 99.999%. The load reduction from 52,000 to 25,000 pounds of steam per hour during the early part of this period did not affect the DRE. The load increase from 25,000 to 55,000 pounds of steam per hour at the end of this period did not reduce DRE.

DRE did not correlate with CO concentration. Three of the five poor DREs occurred during periods when the CO concentration was within the range of good operating practice (less than 170 ppm). Yet, on May 9 at 1508 when the CO was 1970 ppm, the DRE was approximately 99.999%.

The principal investigator reported (Reference 23) that "the boiler was more forgiving than we expected". It was his observation that acceptable (greater than 99.99%) DRE was attained at virtually any steady state operating condition. He reported that disruptions in the waste feed flow caused DRE to be reduced but not dangerously even at extreme conditions. For example, on May 8 at 1600 the steam to the waste atomizer was turned off. Even with the stream of waste reaching the boiler floor, causing relatively high CO emissions and stack gas opacities in excess of 20% approximately 25% of the time, the overall DRE of chlorobenzene was 99.98% and carbon tetrachloride DRE was 99.9996%.

The conclusion, based on these results, is that this boiler is able to maintain excellent DRE of hazardous components under any operating condition within the range of good operating practice. The parameters that control DRE are atomization of the waste fuel and stability of the waste fuel flow rate. Poor atomization, direction of the atomized waste away from the oil flame toward the boiler walls, the fluctuations and rapid changes in the waste flow rate all produced lower DREs. For the most part these lower DREs are not less than 99.99% but are lower than typical values obtained during normal operation.

These tests were done at a packaged water-tube boiler. The conclusions are believed to be applicable to any suspension fired boiler. Inversion of the waste spray (away from the oil flame toward the boiler wall) resulted in slightly lower destruction of hazardous compounds and increased generation of PICs. Similar effects might be predicted for fire-tube boilers. However, the DRE did not fall below 99.99% during the inverted spray experiments, nor was the DRE of the fire-tube boilers tested (Sites G and J) less than 99.99%. The destruction of the hazardous waste appears to occur in the flame zone of the boiler. Maintenance of a steady flame at a sufficiently high temperature appears to assure destruction of hazardous compounds.

Site M

The boiler tested at Site M was a forced draft water-tube with a rated capacity of 350,000 lb/hr of superheated steam at 620 psig and 700°F. The unit is front-fired with four CE R-type burners arranged in a square pattern. Each burner is capable of firing gas and/or fuel oil or liquid wastes. Fuel gas which is fired in all four burners is a mixture of natural gas and process waste gas. Heavy ends wastes from a butanol/propanol production unit are fired in the lower two burners. The butanol/propanol waste stream contains surface oil from a waste-retention pond.

The objective at Site M was to provide confirmatory tests to validate Site L results using an alternative boiler design. The liquid waste stream was spiked with carbon tetrachloride (CCl_4), chlorobenzene (MCB), and 1,2,4-trichlorobenzene (TCB) to quantify DREs for parameters testing (nonsteady and off-design operating conditions) during confiring in an industrial boiler.

Several boiler loads, excess air levels, waste gas and waste oil flow, and various transient conditions were investigated using waste oil selectively spiked with individual or a combination of tracers (CCl_4, MCB, and TCB). The concentration of the tracers were also varied by adjusting their rate of injection. Boiler transient and off-design conditions such as sootblowing, low-excess air, lightoff, reduced atomization, unsteady oil flow, and use of different burner locations were aimed at identifying the POHC DRE failure limits for the boiler waste combinations. Poor combustion and smoky conditions were produced to determine whether DRE values were affected. In one test, the oil injection locations was moved to the two top burners which produced high smoke levels even when the excess oxygen level was increased significantly. In many of of the tests, only one burner (lower right) was working, producing conditions which were unfavorable for efficient combustion since the combustion air was uniformly distributed to all four burners. Near the end of some tests days, the waste oil feed was shut off, and the emissions where checked for any residual PICs and POHCs which might be caused by hysteresis in the boiler (emission of PICs and POHCs after these materials are no longer being introduced into the boiler caused by POHC deposition on soot, and subsequent elation, etc.). POHC and PIC measurements were by the full-VOST (FV), mini-VOST (MV), and EPA modified Method 5 (MM5). Summaries of the test conditions are presented in Table 4.15 through 4.20.

Carbon tetrachloride and monochlorobenzene were measured by the full VOST and mini-VOST. Compliance of the full-VOST data with the quality assurance acceptance criteria could not be fully assessed because the analytical results were reported as a single value for the pair of VOST traps rather than for the individual traps. No peaks were detected for Run FV-9, and therefore this run is not considered valid. Since only one trap was analyzed for Run FV-6B, the results of this run do not meet the second QA acceptance criteria and therefore are not included in calculated the average DRE presented Table 4.21.

The DRE (Table 4.22) of the three compounds used for spiking waste fuel exceeded 99.99% during every run except one. For the lone exception (Run MV-30 in which soot blowing was being conducted), the DRE was greater than 99.98%. As with the Site L test, the high DRE values measured for the chlorinated POHCs did not seem to be affected by the various test conditions aimed at producing poor combustion with high smoke and CO emissions. Values of the DREs measured under these conditions were similar to baseline values measured under normal load and excess air conditions.

Benzene was detected as a measurable POHC in the waste oil. Because the concentration of benzene in the waste oil was very low (barely exceeding 1000 ppm) and because benzene is readily produced as a PIC for the waste oil and natural gas combustion, benzene DRE values calculated from the test results were not considered an accurate indicator of the actual DREs during the waste oil combustion and are not reported here.

TABLE 4.15

MINI-VOST TEST DESCRIPTION
SITE M

VOST #	DATE & TIME SAMPLED		LOAD	O2 (%)	WASTE GAS	WASTE OIL	SPIKE MCB	SPIKE CCl4	SPIKE TCB	OIL BURNERS ON	OIL BURNERS OIL PRESS (psig)	OIL BURNERS ATOM PRESS (psig)	OVERALL DESCRIPTION
										(Most oil flow from rt bottom gun)			
MV-1	7/25/85	0805-0815	Normal	1.2	X								Baseline, low air, no oil
MV-2	7/25/85	1000-1010	Normal	1.3	X	X				R	0-150	160	Waste oil lightoff, low air
MV-3	7/26/85	0740-0750	Normal	4.5	X	X				L,R	28	152	Baseline, normal load & air
MV-4	7/26/85	1135-1145	Normal	3.5	X	X	X			R	22	166	MCB spike start
MV-5	7/26/85	1310-1320	Normal	3.1	X	X	X			R	~26	~160	Low air, smoky
MV-6	7/26/85	1440-1450	Normal	3.5	X	X	X			L,R	26/28	OFF	Low air, atomization off
MV-7	7/26/85	1630-1640	Low	3.5		X	X			R	28	158	Low load, no waste gas
MV-8	7/26/85	1652-1702	Low	3.4		X	X			L,R	26/28	158	Smoky, low load & air, no waste gas
MV-9	7/27/85	0820-0830	Normal	6.5	X	X	X			R	48	160	Max fan capacity
MV-10	7/27/85	0840-0850	Normal	6.5	X	X	X			R	48	160	Max fan capacity
MV-11	7/27/85	0930-0940	Normal	3.5	X	X	X			R	50	158	Low air, hazy
MV-12	7/27/85	0957-1007	Normal	3.3	X	X	X			R	50	158	Low air, hazy
MV-13	7/27/85	1100-1110	Normal	5.5	X	X	X			R	65	160	High air
MV-14	7/27/85	1354-1404	Normal	5.3	X	X	X			R	65	160	Sootblowing
MV-15	7/27/85	1420-1430	Normal	6.0	X	X	X			R	65	160	Sootblowing
MV-16	7/27/85	1715-1725	Normal	3.2	X					OFF			Residual POHC & PIC check, no oil
MV-17	7/28/85	0945-0955	Low	4.0-8.5		X	X	X		L,R	25/25	160	Oil lightoff, low load
MV-18	7/28/85	1015-1025	Low	8.0		X	X	X		L,R	25/25	160	Low load
MV-19	7/28/85	1055-1105	Low	4.1		X	X	X		L,R	25/22	158	Low load, low air
MV-20	7/28/85	1230-1240	Normal	6.7		X	X	X		L,R	48/52	160	High oil firing
MV-21	7/28/85	1314-1324	Normal	4.5		X	X	X		L,R	45/55	160	High oil firing, smoky, low air
MV-22	7/28/85	1331-1341	Normal	5.0		X	X	X		L,R	45/55	160	High oil firing, smoky, low air
MV-23	7/28/85	1430-1440	Normal	5.0-8.0		X	X	X		TOP 2			Smoky 2 top burners only
MV-24	7/28/85	1456-1506	Normal	1.5						OFF			Residual POHC & PIC check, no oil
MV-25	7/29/85	1056-1106	Normal	3.0	X					OFF			Residual POHC & PIC check, no oil
MV-26	7/29/85	1152-1202	Low	8.0-10		X	X	X	X	L	150	160	Low load, lightoff, smoky
MV-27	7/29/85	1352-1402	Normal	6.0		X	X	X	X	R	70	160	Baseline with MCB, CCl4, TCB
MV-28	7/29/85	1600-1610	Normal	9.3		X	X	X	X	R	72	160	High air
MV-29	7/29/85	1810-1820	Normal	5.0		X	X	X	X	L,R	70/65	160	Sootblowing
MV-30	7/29/85	1827-1837	Normal	4.8		X	X	X	X	L,R	70/65	160	Sootblowing
MV-31	7/30/85	0952-1002	Normal	8.0		X				R	50	160	Oil lightoff, Residual POHC & PIC ct
MV-32	7/30/85	1027-1037	Normal	6.2		X		X		R	50	160	Normal load and air
MV-33	7/30/85	1050-1100	Normal	7.5		X		X		R	50	160	Normal load and air
MV-34	7/30/85	1200-1210	Normal	8.1		X		X		R	50	160	High CCl4
MV-35	7/30/85	1252-1302	Normal	6.0		X		X		R	38	160	High CCl4
MV-36	7/30/85	1351-1401	Normal	6.4		X		X		R	38	160	Low CCl4

TABLE 4.15--Continued

VOST #	DATE & TIME SAMPLED		LOAD	O2 (%)	WASTE GAS	WASTE OIL	SPIKE MCB	SPIKE CC14	SPIKE TCB	OIL BURNERS ON	OIL BURNERS OIL PRESS (psig)	OIL BURNERS ATOM PRESS (psig)	OVERALL DESCRIPTION
										(Most oil flow from rt bottom gun)			
MV-37	7/30/85	1425-1435	Normal	6.4		I		I		R	38	160	Low CC14
MV-38	7/30/85	1505-1515	Normal	6.4		I		I		R	38	160	High CC14
MV-39	7/30/85	1550-1600	Normal	--		I				R	38	160	Residual POHC & PIC check
MV-40	7/30/85	1640-1650	Normal	--		I			-	R	38	160	Residual POHC & PIC check
MV-41	7/30/85	1705-1715	Varying	-- --						OFF	(steam on)		Residual POHC & PIC check, no oil
MV-42	7/31/85	0915-0925	Low	4.3		I			I	R	40	160	Unsteady oil flow, low load
MV-43	7/31/85	1202-1212	Normal	4.9		I			I	R	40	160	High TCB
MV-44	7/31/85	1231-1241	Normal	4.9		I			I	R	40	160	High TCB
MV-45	7/31/85	1405-1415	Normal	2.9		I			I	R	50	160	High TCB, low air, smoky
MV-46	7/31/85	1617-1627	Normal	3.0		I			I	R	50	160	Reduced TCB, low air, hazy
MV-47	7/31/85	1635-1645	Normal	2.9		I			I	R	50	160	Reduced TCB, low air, hazy
MV-48	7/31/85	1810-1820	Normal	6.9		I			I	R	45	160	Sootblowing
MV-49	8/01/85	0820-0830	Normal	3.4	I								Residual POHC & PIC check, no oil
MV-50	8/01/85	0914-0924	Normal	8.5	I	I				R	60	160	High air, no spikes
MV-51	8/01/85	1035-1045	Normal	9.1	I	I	I	I		R	60	160	High air, high MCB & CC14
MV-52	8/01/85	1240-1250	Normal	4.8	I	I	I	I		R	50	160	Low air, hazy stack
MV-53	8/01/85	1410-1420	Normal	4.0	I	I	I	I		R	55	160	Low air, smoky, high MCB & CC14
MV-54	8/01/85	1445-1455	Normal	7.2	I	I	I	I		R	55	160	High MCB & CC14
MV-55	8/01/85	1500-1510	Low	7.2		I	I	I		R	55	160	High MCB & CC14

TABLE 4-16

MINI-VOST TEST CONDITIONS
SITE M

				FUEL FLOW RATES			TRACER INJECTION RATE			
VOST NUMBER	BOILER OUTLET TEMP (F)	STEAM LOAD (1000 lb/hr)	BOILER O2 (%)	NAT GAS (1000 dscfh)	WASTE GAS (1000 dscfh)	WASTE OIL (gpm)	CCl4 (gpm)	MCB (gpm)	TCB (gpm)	FLUE GAS (1000 dscfh)
MV-1	565	180	1.2	140	75	0.0	0.00	0.00	0.00	46.5
MV-2	565	180	1.3	140	75	0-7.2	0.00	0.00	0.00	50.9
MV-3	580	184	4.5	115	67.5	6.0	0.00	0.00	0.00	51.8
MV-4	585	184	3.5	115	67.5	5.3	0.00	0.65	0.00	50.8
MV-5	580	182	3.1	115	69	5.5	0.00	0.61	0.00	53.6
MV-6	585	188	3.5	120	69	5.5	0.00	0.61	0.00	53.5
MV-7	540	135	5.5	110	0	3.5	0.00	0.54	0.00	36.6
MV-8	540	130	3.4	110	0	3.5	0.00	0.54	0.00	30.2
MV-9	590	180	6.5	130	45	5.7	0.00	0.06	0.00	55.3
MV-10	590	180	6.5	130	45	5.7	0.00	0.06	0.00	55.3
MV-11	580	180	3.5	130	45	5.7	0.00	0.06	0.00	49.8
MV-12	580	180	3.3	130	45	5.7	0.00	0.06	0.00	49.8
MV-13	585	180	5.5	125	44.2	5.4	0.00	0.05	0.00	50.9
MV-14	580	176	5.3	125	44.2	5.9	0.00	0.06	0.00	58.5
MV-15	580	176	6.0	125	44.2	5.9	0.00	0.06	0.00	58.5
MV-16	570	160	3.2	150	47.25	0.0	0.00	0.00	0.00	44.5
MV-17	550	140-160	4-8.5	110	0	3.8	0.17	0.03	0.00	33.2
MV-18	545	128	8.0	110	0	4.0	0.18	0.03	0.00	36.9
MV-19	540	126	4.1	110	0	3.7	0.25	0.04	0.00	39.5
MV-20	580	190	6.7	135	0	11.5	0.34	0.14	0.00	54.3
MV-21	575	184	4.5	130	0	11.6	0.30	0.13	0.00	45.6
MV-22	575	180	5.0	130	0	11.8	0.31	0.13	0.00	46.8
MV-23	600	160-190	5.0-8.0	125	0	11.6	0.26	0.13	0.00	50.9
MV-24	580	170-185	1.5	210	0	0.0	0.00	0.00	0.00	42.2
MV-25	565	170-185	3.0	160	48	0.0	0.00	0.00	0.00	45.3
MV-26	580	110-165	8-10.2	135-170	0	7-13	0.25	0.08	0.30	64.9
MV-27	580	180	6.0	160	0	6.6	0.15	0.06	0.29	54.1
MV-28	600	176	9.3	160	0	6.0	0.15	0.05	0.26	70.0
MV-29	575	176	5.0	160	0	6.0	0.15	0.05	0.26	55.0
MV-30	575	176	4.8	160	0	6.0	0.15	0.05	0.26	55.0
MV-31	570	175	8.0	150	0	6.0	0.00	0.00	0.00	54.5
MV-32	575	170	6.2	150	0	6.2	0.19	0.00	.00	49.0
MV-33	575	172	7.5	150	0	6.4	0.19	0.00	.00	50.6
MV-34	575	177	8.0	150	0	6.8	0.64	0.00	.00	51.2
MV-35	570	172	6.2	160	0	6.9	0.64	0.00	.00	46.3
MV-36	570	182	6.4	162	0	6.9	0.10	0.00	0.00	48.5
MV-37	570	172	6.4	162	0	6.8	0.10	0.00	0.00	48.4

TABLE 4.16--Continued

				FUEL FLOW RATES			TRACER INJECTION RATE			
VOST NUMBER	BOILER OUTLET TEMP (F)	STEAM LOAD (1000 lb/hr)	BOILER O2 (%)	NAT GAS (1000 dscfh)	WASTE GAS (1000 dscfh)	WASTE OIL (gpm)	CCl4 (gpm)	MCB (gpm)	TCB (gpm)	FLUE GAS (1000 dscfh)
MV-38	570	170	6.4	162	0	6.9	0.64	0.00	0.00	48.5
MV-39	570	180	--	162	0	6.5	0.00	0.00	.00	48.0
MV-40	570	178	--	162	0	6.5	0.00	0.00	.00	48.0
MV-41	570	155-185	--	195	0	0.0	0.00	0.00	0.00	46.4
MV-42	560	148	4.3	132	0	3.7	0.00	0.00	0.42	46.0
MV-43	570	172	4.9	150	0	5.9	0.00	0.00	0.37	54.9
MV-44	570	172	4.9	150	0	5.7	0.00	0.00	0.37	45.6
MV-45	570	172	2.9	150	0	6.4	0.00	0.00	0.37	50.1
MV-46	565	180	3.0	150	0	6.1	0.00	0.00	0.42	50.4
MV-47	565	180	2.9	150	0	6.0	0.00	0.00	0.42	50.4
MV-48	585	172	6.9	150	0	6.0	0.00	0.00	0.28	62.0
MV-49	570	185	3.4	150	63	0.0	0.00	0.00	0.00	49.3
MV-50	590	170-195	8.5	130	64.5	6.1	0.00	0.00	0.00	65.8
MV-51	585	180	9.1	125	46.5	6.0	0.22	0.24	0.01	63.7
MV-52	570	175	4.8	128	46.5	6.0	0.19	0.17	0.01	49.0
MV-53	570	175	4.0	128	46.5	6.0	0.22	0.24	.00	45.0
MV-54	560	165	7.2	128	46.5	6.2	0.22	0.24	.00	58.6
MV-55	560	148	7.2	130	0	6.2	0.22	0.24	.00	44.9

TABLE 4.17

VOST TEST DESCRIPTION
SITE M

VOST #	DATE & TIME SAMPLED		STEAM LOAD	EXCESS O2 (%)	WASTE		SPIKE			OIL BURNERS			OVERALL DESCRIPTION
					GAS	OIL	MCB	CCl4	TCB	ON	OIL PRESS (psig)	ATOM PRESS (psig)	
										(Most oil flow from rt bottom gun)			
FV-1	7/26/85	1135-1155	Normal	3.5	X	X	X			R	22	166	MCB spike start
FV-2	7/26/85	1440-1500	Normal	3.3	X	X	X			L,R	26/28	OFF	Low air atomization off
FV-3	7/27/85	0930-0950	Normal	3.7	X	X	X			R	50	158	Low air, hazy
FV-4	7/28/85	1055-1115	Low	4.2		X	X	X		L,R	25/25	160	Low load, low air
FV-5	7/29/85	1150-1210	Varying	9.0-9.8		X	X	X	X	L	150	160	Low load, lightoff, smoky
FV-6A	7/29/85	1600-1620	Normal	9		X	X	X	X	R	72	160	High air
FV-6B	7/30/85	1200-1220	Normal	8.2		X		X		R	50	160	High CCl4
FV-7	7/30/85	1252-1312	Normal	6.2		X		X		R	38	160	High CCl4
FV-8	7/30/85	1550-1610	Normal	4.5		X				R	38	160	Residual POHC & PIC check
FV-9	7/31/85	0915-0935	Low	4.4-5.0		X			X	R	40	160	Usteady oil flow, low load
FV-10	7/31/85	1405-1425	Normal	3.1		X			X	R	50	160	High TCB, low air, smoky
FV-11	8/01/85	1035-1055	Normal	9	X	X	X	X		R	60	160	High air, high MCB & CCl4
FV-12	8/01/85	1240-1300	Normal	4.8	X	X	X	X		R	50	160	Low air, hazy
FV-13	8/01/85	1410-1430	Normal	4	X	X	X	X		R	55	160	Low air, high smoke, high MCB & CCl4

TABLE 4.18

VOST TEST CONDITIONS
SITE M

VOST NUMBER	BOILER OUTLET TEMP (deg F)	STEAM BOILER LOAD (1000 lb/hr)		FUEL FLOW RATES NAT GAS (1000 dscfh)			TRACER INJECTION RATE CC14 (gpm)			FLUE GAS (1000 dscfh)
			O2 (%)		WASTE GAS (1000 dscfh)	WASTE OIL (gpm)		MCB (gpm)	TCB (gpm)	
FV-1	585	184	3.5	115	67.5	5.3	0.00	0.65	0.00	51.8
FV-2	585	188	3.3	120	69	5.4	0.00	0.60	0.00	51.6
FV-3	580	180	3.7	130	45	5.7	0.00	0.06	0.00	49.8
FV-4	545	128	4.2	110	0	4.1	0.03	0.04	0.00	39.5
FV-5	580	108-184	9-9.8	135-170	0	0.2-12	0.15	0.05	0.18	64.9
FV-6A	600	176	9	160	0	6.2	0.16	0.06	0.27	70.0
FV-6B	575	177	8.2	150	0	6.4	0.64	0.00	.00	50.6
FV-7	570	170	6.2	160	0	6.9	0.64	0.00	0.00	46.3
FV-8	570	175	4.5	162	0	6.5	0.00	0.00	.00	48.0
FV-9	560	140-156	4.5	132.5	0	3.7	0.00	0.00	0.42	46.0
FV-10	570	172	3.1	150	0	6.6	0.00	0.00	0.37	50.1
FV-11	585	176	9	125	46.5	6.0	0.22	0.24	0.01	63.7
FV-12	570	180	4.8	128	46.5	6.0	0.19	0.17	0.01	49.7
FV-13	570	155-180	4	128	46.5	6.2	0.22	0.24	.00	49.0

TABLE 4.19

MODIFIED METHOD 5 TEST DESCRIPTION
SITE M

				EXCESS						OIL BURNERS			
MM5 #	DATE & TIME SAMPLED'		LOAD	O2 (%)	GAS	WASTE OIL	-----SPIKE----- MCB	CCl4	TCB	ON	OIL PRESS (psig)	ATOM PRESS (psig)	OVERALL DESCRIPTION
										(Most oil flow from rt bottom gun)			
MM5-1	7/26/85	0740-840	Normal	3.9	X	X				L,R	28	152	Baseline, normal load & air
MM5-2	7/26/85	1232-1332	Normal	3	X	X	X			L,R	28	166	Low air, smoky
MM5-3	7/27/85	0926-1026	Normal	3	X	X	X			R	50	158	Low air, hazy
MM5-4	7/27/85	1352-1459	Normal	5.5		X	X			R	65	160	Sootblowing
MM5-5	7/28/85	1055-1155	Low	4.5		X	X	X		L,R	25/22	158	Low load, low air
MM5-6	7/29/85	1134-1238	Varying	5-10		X	X	X	X	L,R	150	160	Low load, lightoff, smoky
MM5-7	7/29/85	1334-1434	Normal	5.7-8		X	X	X	X	R	70/70	160	Baseline with MCB, CCl4, TCB
MM5-8	7/29/85	1537-1641	Normal	9		X	X	X	X	R	72	160	High air
MM5-9	7/29/85	1810-1910	Normal	5		X	X	X	X	L,R	70/65	160	Sootblowing
MM5-10	7/31/85	0910-1010	Low	5		X			X	R	45	160	Unsteady oil flow, low load
MM5-11	7/31/85	1131-1231	Normal	4.9		X			X	R	40	160	High TCB
MM5-12	7/31/85	1346-1447	Normal	3.1		X			X	R	50	160	Low air, high TCB, smoky
MM5-13	7/31/85	1608-1708	Normal	3		X			X	R	50	160	Reduced TCB low air, hazy
MM5-14	7/31/85	1810-1858	Normal	6.9		X			X	R	45	160	Sootblowing

TABLE 4.20

MODIFIED METHOD 5 TEST CONDITIONS
SITE M

				FUEL FLOW RATES			TRACER INJECTION RATE			
MM5 #	BOILER OUTLET TEMP (F)	STEAM (1000 lb/hr)	O2 (%)	NAT GAS (1000 dscfh)	WASTE GAS (1000 dscfh)	WASTE OIL (gpm)	CCl4 (gpm)	MCB (gpm)	TCB (gpm)	FLUE GAS (1000 dscfh)
MM5-1	580	184	3.9	115	67.5	6.0	0.00	0.00	0.00	58.2
MM5-2	580	182	3	115	68	5.6	0.00	0.61	0.00	53.6
MM5-3	580	183	3	125	49.5	5.5	0.00	0.06	0.00	49.8
MM5-4	580	176	5.5	125	0	5.9	0.00	0.06	0.00	58.5
MM5-5	540	126	4.5	110	0	3.7	0.25	0.04	0.00	39.5
MM5-6	580	105-200	5-10	135-170	0	0.2-14	0.25	0.08	0.30	64.9
MM5-7	580	180	5.7-8	160	0	6.3	0.15	0.06	0.29	54.1
MM5-8	600	176	9	160	0	6.0	0.15	0.05	0.26	70.0
MM5-9	575	176	5	160	0	6.0	0.15	0.05	0.26	55.0
MM5-10	559	145	5	132.5	0	3.5	0.00	0.00	0.42	46.0
MM5-11	570	170	4.9	150	0	5.8	0.00	0.00	0.37	54.9
MM5-12	567	176	3.1	150	0	6.1	0.00	0.00	0.37	50.1
MM5-13	565	180	3	150	0	6.0	0.00	0.00	0.42	50.4
MM5-14	585	172	6.9	150	0	6.0	0.00	0.00	0.28	62.0

TABLE 4.21

SITE M

Manufacturer: Combustion Engineering
Type: VU-60, Water-Tube
Fuel: Natural Gas, Oil, Waste Gas, and Waste Oil
Waste Stream: Butanol/Propanol Heavy Ends, Process Waste Gas

Design Steam Rate: 350,000 lb/hr
Design Steam Pres.: 620 psig
Test Steam Rate: 200,000 lb/hr
Fraction Waste Fuel Heat Input: 36 - 48 x 10^6 Btu/hr

Compound	Feed Rate mg/sec	Quantity Found (ug)									Test Emission Rate (mg/sec)			Blank Corrected			DRE		
		Baseline Run			Average Blank			Test Runs (Avg)											
		MV	FV	MM5	MV	FV	MM5	MV	FV	MM5	MV	FV	MM5	MV	FV	MM5	MV	FV	MM5
Carbon Tetra-chloride	3,018-64,395	0[a]	b		0.0005	0.031		0.073	0.166		184.6			No	No		99.9995	99.9997	
Chlorobenzene	2,095-45,391	0[a]	c		0.103	0		0.129	0.057		285.5			No	No		99.9998		
1,2,4-Trichlo-robenzene	23,717-38,312			0			0			11.7			191.9			No			99.9994

[a] No CCl_4 or C_6H_5Cl was detected during first three baseline runs. During runs made to test for hysteresis (i.e., after POHC feed stopped: MV-16, MV-24, MV1-5, MV-31, MV-39, MV-40, MV-41, MV-49, and MV-50) the collected CCl_4 ranged from 0.0025 to 0.365 ug with an average value of 0.072 ug while C_6H_5Cl ranged from 0 to 0.024 ug with an average value of 0.011 ug.

[b] Boiler burning natural gas and unspiked waste oil during single test for hysteresis resulted in 0.130 ug collected or trap. No baseline VOST sampling conducted several hours after spiked waste firing.

[c] Boiler burning natural gas and unspiked waste oil during simple test for boiler hysteresis resulted in 0.140 ug collected on traps. No baseline VOST sampling conducted several hours after spiked waste firing.

TABLE 4.22

DRE GROUPED BY TEST CONDITIONS
SITE M

TEST #	OVERALL DESCRIPTION	DRE CCL4	DRE MCB	DRE TCB	DRE BENZENE
MV-27	Baseline with MCB, CCl4, TCB	99.99961	99.99968	--	--
MM5-7	Baseline with MCB, CCl4, TCB	--	--	100	--
MV-32	Normal load and air	99.99837	--	--	--
MV-33	Normal load and air	99.99767	--	--	--
MV-9	Max fan capacity	--	99.99967	--	--
MV-10	Max fan capacity	--	100	--	--
MV-13	High air	--	99.99981	--	--
FV-6A	High air	100	99.99689	--	99.76775
MV-28	High air	99.99988	99.99886	--	--
MM5-8	High air	--	--	100	--
MV-5	Low air, smoky	--	99.99491	--	--
MV-11	Low air, hazy	--	99.99924	--	--
MV-12	Low air, hazy	--	99.99978	--	--
FV-3	Low air, hazy	--	99.99861	--	94.71648
MV-21	High oil firing, smoky, low air	99.99949	99.99956	--	--
MV-22	High oil firing, smoky, low air	99.99940	99.99855	--	--
MV-52	Low air, hazy stack	99.99937	99.99947	--	--
MV-53	Low air, smoky, high MCB & CCl4	99.99932	99.99990	--	--
FV-13	Low air, high smoke, high MCB & CCl4	99.99968	99.99938	--	97.49198
FV-12	Low air, hazy	99.99987	99.99860	--	99.66780
MM5-12	Low air, high TCB, smoky	--	--	99.99773	--
MM5-13	Reduced TCB low air, hazy	--	--	99.99979	--
FV-10	High TCB, low air, smoky	--	--	--	98.64499
MV-6	Low air, atomization off	--	99.99749	--	--
FV-2	Low air atomization off	--	100	--	--
MV-7	Low load, no waste gas	--	99.99166	--	--
MV-8	Smoky, low load & air, no waste gas	--	100	--	--
MV-18	Low load	99.99933	99.99705	--	--
MV-19	Low load, low air	99.99951	100	--	--
FV-4	Low load, low air	99.99681	99.99789	--	98.29147
MV-26	Low load, lightoff, smoky	99.99922	99.99967	--	--
FV-5	Low load, lightoff, smoky	100	99.99973	--	99.99779
MM5-6	Low load, lightoff, smoky	--	--	99.99991	--
MM5-10	Unsteady oil flow, low load	--	--	99.99934	--
MV-55	High MCB & CCl4	99.99955	99.99996	--	--
MV-54	High MCB & CCl4	99.99963	99.99994	--	--
MV-51	High air, high MCB & CCl4	99.99875	99.99989	--	--
FV-11	High air, high MCB & CCl4	99.99976	99.99884	--	99.86947
MV-34	High CCl4	99.99931	--	--	--

TABLE 4.22--Continued

TEST #	OVERALL DESCRIPTION	DRE CCL4	DRE MCB	DRE TCB	DRE BENZENE
FV-6B	High CCl4	99.99911	--	--	99.59178
MV-35	High CCl4	99.99928	--	--	--
FV-7	High CCl4	99.99865	--	--	98.69712
MV-38	High CCl4	99.99981	--	--	--
MM5-11	High TCB	--	--	99.99899	--
MV-36	Low CCl4	99.99454	--	--	--
MV-37	Low CCl4	99.99793	--	--	--
MV-4	MCB spike start	--	99.99792	--	--
FV-1	MCB spike start	--	99.99991	--	99.10602
MV-17	Oil lightoff, low load	99.99890	99.99952	--	--
MV-14	Sootblowing	--	99.99962	--	--
MV-15	Sootblowing	--	99.99994	--	--
MM5-14	Sootblowing	--	--	99.99895	--
MV-29	Sootblowing	100	100	--	--
MV-30	Sootblowing	99.99980	99.96762	--	--
MM5-9	Sootblowing	--	--	100	--
MV-20	High oil firing	99.99976	99.99976	--	--
MV-23	Smoky 2 top burners only	99.99975	99.99941	--	--
FV-9	Usteady oil flow, low load	--	--	--	100
	AVERAGE DRE	99.9991	99.9987	99.9994	98.8873

It is concluded from the results that the co-firing of hazardous waste in the tested boiler produce very high DREs of the waste compounds within the normal range of boiler operating conditions including transients such as startup, insufficient combustion air, and sootblowing.

Site N

The boiler tested at Site N was a coal-fired spreader stoker with a rated capacity of 150,000 lb/hr of saturated steam at a design pressure of 290 psig. It is equipped with a fly ash control system, consisting of a mechanical collector in series with a baghouse. The boiler is used to dispose of industrial sludge which is injected at opposite sides of the furnace at approximately 3 feet above the traveling grate.

The objective at site N was to provide confirmatory testing to validate parameters testing and Site L and M by measuring principle organic constituents (POHC), DRE and PIC emissions for a typical coal-fired spreader stoker. Chlorinated organic and metal traces were added to the sludge to broaden the range of POHCs available for DRE quantification and to determine the partitioning of hazardous metals to the ash and flue gas streams generated. Tests were also performed with oil used as a carrier for these trace pollutants.

Eighteen boiler operating conditions, shown in Tables 4.23 through 4.26, were investigated during the site N test program. The test matrix consisted of four distinct series of tests. The initial four baseline test conditions established the background emission data with coal combustion only and coal with sludge co-fired. Background emissions with coal and No. 2 oil feed were measured during test condition 5. For these background tests, the sludge and No. 2 oil were not spiked with either organic or inorganic tracers. Both normal and low steam load test conditions were investigated. Excess combustion air was maintained at normal operating levels during these tests corresponding to approximately 7% excess O_2 at the boiler economizer exit. Baseline tests were repeated during test conditions 14A and 17 to determine the reproducibility of initial baseline results during and at the conclusion of the test program.

The second series of tests, 6 through 10, consisted of tests with coal and sludge spiked with TCE and TCB, alternatively. Boiler operation was set on manual and tested at normal load and excess air levels (test condition 6 and 7), low load and high excess air (test condition 8 and 8A), low load and low excess air test condition 10). Combustion excess air was varied by adjustments in both undergrate and OFA.

The third series of tests, conditions 2 through 14A, were performed with the boiler co-fired with No. 2 oil spiked with TCE and TCB, alternately. These tests were performed to provide a comparison of POHC, DRE, and PIC emissions with an alternative liquid stream. As in the case of the sludge co-fire test series, variations in combustion excess air and boiler load were investigated.

The fourth and final series of tests, represented by test conditions 15 and 16, were performed to investigate the partitioning of metal tracers (lead and chromium) spiked in the sludge and No. 2 oil liquid streams. During these tests, TCB was also simultaneously injected along with the metal tracers. DRE calculations were performed on the TCE and TCB POHCs spiked in the simulated

TABLE 4.23

SITE N TEST MATRIX

						Spiking rate (gpm)			Sampling baghouse inlet				Sampling baghouse outlet						Sampling-ash discharge streams			Sampling-feed streams		
Test condition	Boiler load (10^3 lb/hr)	Overfire air setting	Overall excess O_2	Waste stream	Waste stream flow (gpm)	TCE	TCB	$Cr^a (NO_3)_3$ and $Pb^a (NO_3)_2$	MM5	Andersen	VOST	Mini-VOST	CM	MM6	M5	VOST	Mini-VOST	Andersen	Bottom hopper	Mechanical hopper	Baghouse hopper	Coal	Waste stream	Test duration hours
1	130-140	Normal	Normal	--	--	--	--	--	1	1	1	2	X	1	1	--	--	1	1	1	1	1	--	4
2	130-140	Normal	Normal	Sludge	4.0	--	--	--	1	1	1	2	X	1	1	--	--	1	1	1	1	1	1	4
3	80-90	Normal	Normal	--	--	--	--	--	1	--	--	2	X	--	1	--	--	--	1	1	1	1	--	4
4	80-90	Normal	Normal	Sludge	4.0	--	--	--	1	1	--	2	X	1	1	--	--	1	--	--	--	--	--	4
5	130-140	Normal	Normal	No. 2 oil	4.0	--	--	--	1	--	1	2	X	--	--	--	--	--	--	--	--	1	--	3
6	130-140	Normal	Normal	Sludge	4.0	0.2	--	--	1	--	1	2	X	1	--	--	2	--	--	--	--	1	--	4
7	130-140	Normal	Normal	Sludge	4.0	--	0.2	--	1	--	--	2	X	1	--	--	2	--	1	1	1	1	1	4
8	80-90	High	High	Sludge	4.0	0.2	--	--	--	--	1	2	X	1	--	--	--	--	--	--	--	1	--	2
8A	80-90	High	High	Sludge	4.0	0.44	--	--	--	--	--	2	X	--	--	--	--	--	--	--	--	--	--	1
9	80-90	Low	Low	Sludge	4.0	0.2	--	--	1	1	1	2	X	1	--	--	--	1	--	--	--	1	1	4
10	80-90	Normal	Normal	Sludge	4.0	0.2	--	--	--	--	1	2	X	--	--	--	--	--	--	--	--	1	--	2
12	80-90	Normal	Normal	No. 2 oil	4.0	--	0.2	--	1	--	--	2	X	1	1[b]	--	1	--	1	1	1	1	--	3
13	80-90	High	High	No. 2 oil	4.0	--	0.2	--	1	--	--	2	X	--	--	--	1	--	1	1	1	1	--	3
14	80-90	Low	Low	No. 2 oil	4.0	0.2	--	--	1	1	1	2	X	1	1[b]	--	--	1	--	--	--	--	--	3
14A	80-90	Normal	Normal	No. 2 oil	4.0	--	--	--	--	--	--	2	X	--	--	--	--	--	--	--	--	--	--	1
15	130-140	Normal	Normal	No. 2 oil	4.0	--	0.2	0.1	1	--	1	2	X	1	1	--	--	--	1	1	1	1	--	4
16	80-90	High	High	Sludge	4.0	--	0.2	0.1	1	1	--	2	X	1	1	--	--	1	1	1	1	1	1	4
17	130-140	Normal	Normal	Sludge	4.0	--	--	--	1	1	1	2	X	--	--	--	--	1	1	1	1	1	--	4

[a] Both lead and chromium nitrate will be injected in a water solution as discussed in Section 3.
[b] Substitute EPA Method 5 with Modified Method 5 to include semivolatile organics at baghouse outlet.

Legend:
VOST -- Volatile organic sampling train
MM5 -- Modified EPA Method 5 for particulate, metals, and semivolatile organics
MM6 -- Modified EPA Method 6 for HCl emissions
Andersen -- Particulate impactor for particle sizing and metal distribution
CM -- Continuous emission monitors for O_2, CO_2, CO, HC, SO_2, and NO_x

TABLE 4.24

BOILER TEST CONDITIONS--BASELINE TESTS
SITE N

Test condition	Test description	Steam load (10^3 lb/hr)	Steam pressure (psig)	Feedwater pressure[a] (psig)	Excess O_2 (percent)	OFA Pressure (in H_2O)				Dust collector draft (in H_2O)	Baghouse pressure drop (in H_2O)	Economizer out temperature (°F)	Opacity (percent)		Sludge injection (gpm)		No. 2 oil injection (gpm)	
						Header	Front	Rear	Flyash reinjection				Baghouse inlet	Baghouse outlet	North gun	South gun	North gun	South gun
1	High steam load, coal only	129-137 (133)[b]	260-265 (262)	390-395 (393)	6.0-7.2 (6.6)	20	17	25	18	-8.0	4.6-4.8 (4.7)	400	27-32 (29)	2.5-3.0 (3.0)	--	--	--	--
2	High steam load, coal and sludge	125-130 (128)	260-265 (262)	397-400 (400)	6.7-7.0 (6.9)	21	16	25	18	-8.0	4.6-4.8 (4.7)	400	26-31 (29)	3.0-3.5 (3.0)	2.0-2.9 (2.5)	1.8-4.0 (2.6)	--	--
3	Low steam load, coal only	89-90 (89)	255	390-394 (393)	7.2-8.4 (7.6)	16.5	16	24	19	-4.2	3.4-3.7 (3.5)	369	26-27 (26)	2.0-3.0 (2.5)	--	--	--	--
4	Low steam load, coal and sludge	85-94 (89)	255-258 (257)	395-400 (396)	7.4-8.0 (7.7)	16	16	24	19	-4.2	3.6-3.7 (3.7)	365	26-41 (37)	3.0	1.7-2.2 (2.0)	1.7-2.5 (2.1)	--	--
5	High steam load, coal and no. 2 oil	132-138 (135)	265	396	6.1-6.6 (6.4)	21	17	24	18	-7.7	4.5-4.7 (4.6)	400	26-30 (28)	3.0-3.5 (3.2)	--	--	2.0	2.1
14A	Low load, coal and oil	96	260	395	NA	15	8.6	18	18	-5.0	NA	375	27	3	--	--	2.0	0 2.0
17	High steam load, coal and sludge	121-132 (127)	260-264 (262)	390-395 (393)	6.1-6.5 (6.3)	16	18	24	19	-7.7	5.1	400	24-29 (27)	2.5	2.0-2.1 (2.1)	0.8-2.7 (1.3)	--	--

NA -- Not available.

[a] Feedwater temperature to economizer = 221°F.
[b] Numbers in parenthesis are arithmetic averages of recorded operating data.

TABLE 4.25

SLUDGE CO-FIRE TEST CONDITIONS
SITE N

Test condition	Test description	Steam load (10³ lb/hr)	Steam pressure (psig)	Feedwater pressure^a (psig)	Excess O₂ (percent)	OFA Pressure in (H₂O)				Dust collector draft (in H₂O)	Baghouse pressure drop (in H₂O)	Economizer out temperature (°F)	Opacity (percent)		Sludge injection (gpm)		TCE Injection (gpm)	TCB Injection (gpm)	Metals Solution Injection (gpm)
						Header	Front	Rear	Flyash reinjection				Baghouse inlet	Baghouse outlet	North gun	South gun			
6	High load, coal, sludge and TCE	133-136 (135)^b	262	395	6.4-7.0 (6.6)	21	17	27	20	-8.0	4.8	400	26-33 (29)	3.0-3.2 (3.1)	1.5-2.0 (1.8)	1.7-2.3 (2.0)	0.19	--	
8	Low load, high air, coal, sludge and TCE	80-90 (85)	260	395	9.4-10.0 (9.7)	16.5	17.5	21	19	5.6	4.0	380	26-29 (28)	4.0	1.9-2.0 (2.0)	1.9-2.0 (2.0)	0.17-0.22 (0.20)	--	--
8A	Low load, high air, coal, sludge and high TCE	80-90 (89)	265	395	9.4	18	17.5	20.5	19	-5.6	4.0	380	23-30 (29)	4.0	2.0	1.8-2.2 (2.0)	0.44	--	--
9	Low load, low air, coal, sludge and TCE	85-90 (88)	260	395	6.7-7.5 (6.9)	16	9	19	20	-3.7	3.5	365	28-35 (32)	3.0-3.5 (3.2)	1.8-2.5 (2.0)	0.2 (1.8)	0.23	--	--
10	Low load, coal sludge and TCE	86-90 (88)	260	395	8.0	16.5	17.5	21	19	-5.3	3.0	370	26-29 (28)	3.2	2-2.3 (2.2)	1.8-2.0 (1.9)	0.22	--	
7	High load coal, sludge and TCB	120-130 (129)	266	395	6.0-6.8 (6.2)	18	18.5	25	18.5	-9.0	5.6	412	34-40 (36)	3.5-4.1 (3.8)	1.7-2.1 (2.0)	1.7-2.3 (2.0)	--	0.19-0.21 (0.2)	
14^c	Low load, high air, coal sludge with TCB and metals	89-95 (91)	262	392	8.0-8.7 (8.5)	15.5	18	24	18.5	-6.0	4.6	390	29-33 (31)	10	1.5-2.0 (1.8)	1.6-2.7 (2.1)	--	0.21	0.14

^a Feedwater temperature to economizer = 222°F.
^b Numbers in parenthesis are the arithmetic average of recorded operating.
^c Chromium and lead also injected during this test.

TABLE 4.26

NO. 2 OIL CO-FIRE TEST CONDITIONS
SITE N

Test condition	Test description	Steam load (10^3 lb/hr)	Steam pressure (psig)	Feedwater pressure[a] (psig)	Excess O_2 (percent)	OFA Pressure in (H_2O)				Dust collector draft (in H_2O)	Baghouse pressure drop (in H_2O)	Economizer out temperature (°F)	Opacity (percent)		No. 2 oil Injection (gpm)		TCE Injection (gpm)	TCB Injection (gpm)	Metals Solution Injection (gpm)
						Header	Front	Rear	Flyash reinjection				Baghouse inlet	Baghouse outlet	North gun	South gun			
12	Low load, oil and TCB	90-91 (91)[b]	260	394-397 (395)	6.5-6.9 (6.7)	15.5	8.5	18	19	-4.4	3.9	370-375 (372)	27-30 (28)	3	2.0	2.2	--	0.23	--
13	Low load, high air, oil and TCB	91-95 (93)	260-262 (261)	395	9	18.5	12.0	24	18.5	-8	4.9	395-400 (398)	29-35 (31)	3.5	2.0	2.2	--	0.21	--
15[c]	High load, oil, TCB and metals	127	265	388-395 (391)	5.5-6.6 (6.1)	15.5-16 (15.7)	18.5	25	18.5	-7.2	4.8	400	24-29 (27)	2.5	2.1	2.2	--	0.20	0.14
14	Low load, coal, oil with TCE	90-94 (91)	260-263 (261)	390-395 (394)	6.4-7.1 (6.8)	15-15.5 (15.2)	8.5	18	18.5	-4.6	3.6-4.0 (3.8)	370-372 (371)	24-27 (25)	3	2.0	2.1	0.21	--	--

[a] Feedwater temperature to economizer = 222°F.
[b] Numbers in parenthesis are arithmetic averages or recorded operating data.
[c] Chromium and lead also injected during this test.

liquid waste streams. Tables 4.27 through 4.29 summarize these results. DRE results on TCE from six test conditions and a total of 15 individual measurements clearly indicate that the destruction of TCE was approximately 99.9999% or well above current regulations for commercial incinerators. Some reduction in DRE is evident during test condition 8, where excess air was increased well above the typical operating setting of the boiler. DRE results for TCB averaged 99.997% indicating thermal destruction approximately equal to that of TCE.

It is concluded from the results that co-firing hazardous wastes in the coal-fired spreader stoker boiler produces high DREs of waste compounds within the normal ranges of boiler operating conditions including low-load and high-excess air.

Site O

The boiler tested at Site O was a coal stoker that had been converted to fire natural gas, fuel oil, or liquid wastes. It is capable of delivering 22,000 pounds of 95 psig steam per hour. The exhaust gas from the boiler was tested by EPA Method 23 (inert plastic bag samples). All other tests reported herein were done by either VOST or MM5, or both. Analyses were done on-site by GC/FID or GC/ECD. Samples from all other sites were shipped to the laboratory for GC/MS analysis. The waste fuel consisted of alcoholic still bottoms to which the test team added methyl chloroform (1,1,1 trichloroethane). The waste contained no other hazardous material (Appendix VIII).

The QAAC for this site was a demonstration that the method (Method 23) would have detected methyl chloroform had it been present. Before going to Site O the testing organization added known quantities of methyl chloroform to samples of the exhaust gas from a residential heater that was burning a fuel similar to the Site O waste fuel. Recovery of the spikes was good (95 to 96%). There was a further demonstration that low concentrations (0.5, 0.005 ppm) of methyl chloroform were stable in the bags for up to 3 days. All sample analyses were completed within an hour of their collection. These tests were taken as evidence that had methyl chloroform been present in the stack gas at Site O, it would have been detected. Therefore, the data were accepted.

All stack gas methyl chloroform concentrations were less than the limit of detection of the analytical procedure (Table 4.30). The test average DRE of methyl chloroform was greater than 99.999%. The boiler operated at the same steady conditions throughout the seven test runs. The carbon monoxide concentration in the stack gas during runs 2 and 3 (210 ppm and 110 ppm) was higher than the average (40 ppm) measured during the other five tests. There was no discernible effect on the DRE of methyl chloroform nor on the other two non-hazardous compounds (methanol and methyl acetate) that were measured.

Products of Incomplete Combustion

Several means have been suggested by which compounds that were not present in the fuel or waste fuel burned in a combustion source may appear in the exhaust gas of that source. *There are two general mechanisms by which* products of incomplete combustion (PICs) may be formed. One is formation of products of partial oxidation of fuel components. The formation of aldehydes

TABLE 4.27

TCE DESTRUCTION
SITE N

Test no.	TCE injection rate (g/s)	Run no.	TCE emission rate		TCE-DRE (percent)	
			Mini-VOST (µg/s)	VOST (µg/s)	Mini-VOST	VOST
6	17.62	1	17	38	99.99990	99.9998
		2	33		99.9998	
8	18.55	1	130	72	99.9993	99.9996
		2	32		99.9998	
8A	40.80	1	13	NA	99.99997	NA
		2	10		99.99998	
9	21.33	1	ND	NA	100	NA
		2	ND		100	
10	20.40	1	8	ND	99.99996	100
		2	5		99.99998	
14	19.47	1	2.8	NA	100	NA
		2	2.8		100	
Weighted average					99.99991	99.9998

ND -- Not detected, less than 1 µg/sec.
NA -- Not available, sample not taken.

TABLE 4.28

TCB DESTRUCTION
SITE N

Test no.	TCB injection rate (g/sec)	TCB[a] emission rate (μg/sec)	TCB DRE (percent)
7	19.81	17	99.99991
12	22.78	120	99.9995
13	20.80	59	99.9997
15	19.81	32	99.9998
16	20.80	74	99.9996
Weighted average			99.9997

[a] Baghouse inlet condition -- emissions are not blank corrected.

TABLE 4.29

SITE N

Manufacturer: Riley
Type: Coal-Fired Spreader Stoker
Fuel: Coal
Waste Stream: TCB & TCE Spiked Sludge and No. 2 Oil

Design Steam Rate: 150,000 lb/hr
Design Steam Pres.: 290 psig
Test Steam Rate: 130,000-140,000 lb/hr

		Quantity Found (ppm)									Test Emission Rate (ug/sec)			DRE		
		Baseline Run			Blank Run			Test Run								
Compound	Feed Rate mg/sec	MV	V	MM5	MV	V	MM5	MV	V	MM5	MV	V	MM5	MV	V	MM5
TCE	14,369.74- 33,218.36	.0029	0		.0032	.0028		.0073	.056			.037		99.9999	99.9996	
TCB	15,489.46- 18,786.41			.00243			0			.0064						99.9997

TABLE 4.30

SITE O

Manufacturer: Combustion Engineering
Type: Converted Coal Stoker
Fuel: No. 6 Oil and Natural Gas
Waste Stream: Alcoholic Still Bottoms

Design Steam Rate: 22,000 lb/hr
Design Steam Pres.: 95 psig
Test Steam Rate: 7,600 lb/hr
Fraction Waste Fuel
  Mass: 100%
  Heat Input: 100%

		Quantity Found (ppm)					
Compound	Feed Rate mg/sec	Base-line Run	Aver-age Blank	Test Runs (avg)	Test Emission Rate (g/sec)	Blank[a] Cor-rected	DRE
methyl chloroform	113.9	NR	NA	<0.02	<82.5	No	>99.999

NR - No baseline run at this site.
NA - Not applicable.

NOTE:

$$\text{DRE} = \frac{(\text{Feed Rate}) - (\text{Test Emission Rate})}{\text{Feed Rate}} \times 100\%$$

[a] Indicates whether or not the results of laboratory and field blank analyses were subtracted from the results of sample analyses prior to calculation of DRE.

during incineration of refuse is an example of this mechanism. Formation of low molecular weight hydrocarbons (C_1-C_6) during combustion of coal and heavy oil fuels is another. The second general mechanism is a reaction of free radicals or other molecular fragments produced in the high temperature flame to produce different compounds. The products of these reactions may have higher molecular weights than the fuel components. Benzene, polynuclear aromatic compounds, and soot particles appear to be formed in this manner.

There are also means by which fuel-absent compounds may appear in the exhaust gas that are unrelated to the combustion. These include evaporation of lubricating oils from mechanical equipment downstream of the furnace, compounds that were present in the ambient air that was used in the furnace, and compounds introduced with the compressed air used in soot blowing. Where the combustion sources are equipped with scrubbers the water may be a source of organic compounds. These may exist in the fresh water supply, be introduced by other processes where water re-use is practiced, or they may have been added in the form of fungicides or other water treatment chemicals. Compounds from these sources are not PICs, but rather, are flue gas contaminants.

A third source of fuel-absent compounds in samples taken from the flue gas is contamination of those samples during sampling or analysis. This contamination can be external. For example, large amounts of Freon were identified in Tenax®-GC samples from one site. Apparently the refrigerator in which the samples were stored was defective and Freon invaded the samples. The contamination can also be internal. Several investigators have reported that benzene appears to be a product of thermal degradation of Tenax®-GC. Others have attributed the presence of several C_5-C_9 alcohols and ketones in exhaust gas samples to the degradation of XAD resin. In addition, there is evidence that compounds sorbed by porous polymer resins are not quantitatively removed during their preliminary cleanup. Successive cleanings release additional amounts of these compounds. Thus, it is possible that a measured compound may be the residue of some past sample or contamination.

Ascription of the presence of a compound to its formation by incomplete combustion of other compounds must be done with caution in light of the small quantities of matter involved, the potential for contamination, and the potential for degradation of the organic polymer sorbents that are used for these tests. The PICs reported at Sites A and C (see Table 4.17) are an example of these difficulties. The limits of analytical detection for these compounds are typically 1 microgram. Even though some were detected at levels several times their limit of detection they are, on the average, found at only a few micrograms above this limit. Further, their concentration in the co-fired samples is not greatly more (and in some cases less) than their concentrations in the baseline run and blank samples. The difficulties with contamination and high blank values are even more pronounced with the VOST method than they are with the MM5 procedure. Methylene chloride, for example, is found in nearly every VOST tube analyzed. This compound is a common laboratory solvent. It is used for the MM5 extractions and clean-ups. Creation of a protocol and an environment that would allow credible sampling and analysis of methylene chloride would require a monumental effort.

Much of the PIC data (Table 4.31) are more demonstrative of the difficulty of maintaining contamination-free VOST samples than they are of the formation of PICs. Only at Site G were the amounts of PICs (chloroform, perchloroethylene, chlorobenzene, chloromethane, and 1,2 dichloroethane) found in the samples significantly higher than blanks. Chloroform was found in significant concentrations in the stack gas during all eight of the runs. Over 80% of the total quantity of the other four compounds found was found in one of the eight runs. The remaining 20% was distributed among five other runs. The boiler operation, as characterized by the flue gas concentration of combustion gases and particles, was not any different during this run than during the other runs. The quantities of these compounds emitted were small. If the total rate of emissions of these five compounds is added to the total rate of emissions of the POHCs, the total hazardous compound emission rate is less than 14 mg/sec (PICs = 3.6 mg/sec; POHCs = 0.3 mg/sec). The DRE of haz-hazardous chlorinated compounds would be 99.998%.

A different sampling and analysis procedure was used at Site L, M, and N. At these sites Tenax® tubes that had been cleaned and sealed in the laboratory were recleaned immediately prior to use in an in-field desorber/gas chromatograph with a Hall electrical conductivity detector (GC/HECD). In this way the lack of contamination could be verified immediately prior to the use of a Tenax® tube. The tubes were then taken to the stack and samples accumulated. The tubes were analyzed in the field by GC/HECD within two hours of sample collection. Blank tubes that were treated similarly (taken to the stack, opened, closed, returned to the laboratory, and analyzed) showed insignificant (2 to 5 ng total chlorinated compounds) amounts of contamination.

Several PICs were measured by this technique. Identification of the compounds was made by matching their relative retention times on the column to those of known compounds.

The measured PICs at the three parametric testing sites (L, M, and N) are summarized in Table 4.32 through 4.34. The PIC emissions were generally on the same order of magnitude as those measured during baseline testing and as the POHC emissions. Exceptions to this generalization were observed during sootblowing and waste atomizer upsets when the PIC emissions were much greater than the POHC emissions. Curiously, POHC emissions were lower than usual during the sootblowing and atomizer upsets.

Tables 4.32 and 4.33 give the PIC/POHC ratios calculated from the PIC and POHC emissions for Sites L and M. The use of PIC/POHC ratios without their associated PIC and POHC emissions is considered a bad practice because it can lead to misconceptions about the magnitude and risks associated with PIC emissions. This ratio is calculated from both the PIC and POHC emission rates and consequently, a high PIC/POHC ratio does not necessarily indicate a high PIC emission level. It could simply mean that the POHC level was very low indicating a high DRE was achieved.

The emission rate of PICs was highest during periods of unstable waste feed (low unstable flow of waste, waste startup, and waste spray directed away from the oil flame). The amount of organic chlorine released as PICs ranged from approximately 0.02 to 0.0002% of the POHCs fed to the boiler. There was no discernible relationship between PIC emission rate and carbon monoxide or oxygen concentrations, boiler load, or load changes.

TABLE 4.31

REPORTED PRODUCTS OF INCOMPLETE COMBUSTION

Site	Compound	ug/Sample Baseline Run	Average Blank	Average Co-Fire Run
A	2-chlorophenol	ND	ND	4
	2,4-dichlorophenol	ND	ND	2
	2,4,6-trichlorophenol	ND	ND	6
	nitrobenzene	7	ND	1
	dichlorobenzene	ND	ND	2
	trichlorobenzene	ND	ND	2
B	none reported	--	--	--
C	butylbenzylphthalate	22	5	6
	dibutylphthalate	35	5	8
	diethylphthalate	4	4	7
	chrysene	ND	ND	2
	fluoranthene	ND	ND	1
	benzo(a)anthracene	ND	ND	1
D	carbon tetrachloride	ND	NA	0.07
	chloroform	ND	0.032	0.08
	1,1,2-trichloroethane	ND	ND	0.007
	methylene chloride	ND	NA	0.12
E	chloroform	ND	0.27	4.8
	methylchloroform	ND	0.064	0.49
	perchloroethylene	1.1	0.51	4.3
F	none reported	--	--	--
G	chloroform	NR	0.057	21
	chloromethane		0.21	2.4
	chlorobenzene		0.68	1.8
	1,2-dichloroethane		0.01	7.4
	perchloroethylene		0.18	4.0
H	---- Test Report Not Available ----			
I	none found			
J	none reported			
K	substituted phenols	ND	ND	trace
O	none reported			

ND - None detected.
NA - Not analyzed.

NR - No baseline run at this site.

TABLE 4.32

COMPARISON OF PIC AND POHC CONCENTRATION AT SITE L

DATE	TIME	Sample Protocol+	FUEL	CONDITIONS	CCl4 (ng/l)	Chlorobenzene (ng/l)	Chlorinated PICs (ng/l)*	PIC/POHC Ratio*
25-Apr	1445	FULL VOST	GAS	TSB BASELINE	ND	ND	13	
25-Apr	1605	FULL VOST	GAS	TSB BASELINE	ND	ND	7	
25-Apr	1732	FULL VOST	GAS	TSB BASELINE	1.8	ND	16	9.4
27-Apr	1446	FULL VOST	GAS	BASELINE	7.7	0.3	14	1.9
27-Apr	1626	FULL VOST	GAS	BASELINE	6.3	0.4	11	1.3
27-Apr	1755	FULL VOST	GAS	BASELINE	ND	0.8	8	40.0
08-May	1154	35	GAS	TSE HIGH GPM BASE	0.3	0.4	3	3.3
08-May	1431	36	GAS	TSE HIGH GPM BASE	1.1	11.0	3	0.3
08-May	1447	39	GAS	LOW GPM	280.0	ND	204	0.5
08-May	1600	40	GAS	NO ATOMIZER	4.5	62.0	6	0.3
08-May	1641	43	GAS	LOW GPM/O2	1.1	2.0	2	1.1
08-May	1710	46	GAS	LOW O2 WASTE INCREASE	ND	0.6	37	193.6
08-May	1740	48	GAS	LOW O2 BASELINE	0.5	ND	2	3.1
08-May	2103	FULL VOST	GAS	WASTE OIL STARTUP	0.6	9.4	25	6.9
08-May	2224	FULL VOST	GAS	LOW ATOM STEAM (VARY)	1.43	28.65	36	3.8
08-May	2333	50	GAS	SOOT BLOW	4.6	73.0	7	0.3
09-May	0020	53	GAS	EA TRANSIENTS	@NA	20.0	0.3	0.05
09-May	0921	57	GAS	START UP DUAL VOST	0.3	3.9	0.3	0.2
09-May	1038	60	GAS	LOW O2	2.0	12.0	10	1.7
09-May	1142	62	GAS	LOW O2 & GPM	0.3	ND	52	189.5
09-May	1311	66	GAS	LOW O2 & GPM	62.0	31.0	2	0.03
09-May	1410	67	GAS	GAS BASELINE	18.0	20.0	7	0.3
09-May	1508	69	GAS	LOAD REDUCTION	27.0	12.0	101	3.5
09-May	1702	FULL VOST	GAS	LOW LOAD, MODERATE O2	4.1	7.0	22	3.7
09-May	1801	74	GAS	LOW LOAD, LOW O2	28.0	19.0	8	0.3
09-May	1946	76	GAS	LOW LOAD/O2/GPM	9.0	10.0	3	0.2
09-May	2015	77	GAS	GPM TRANSIENTS	15.0	12.0	6	0.3
09-May	2153	81	GAS	LOAD INCREASE	2.0	0.7	1	0.7
09-May	2301	83	GAS	LOAD DECREASE	3.0	2.0	2	0.5
09-May	2346	86	GAS	SOOTBLOW LOW LOAD	2.3	1.2	1	0.3
10-May	0716	87	OIL	LOW LOAD BASELINE	1.6	0.8	2	1.1
10-May	0945	90	OIL	LOW LOAD BASELINE	3.9	1.0	4	0.9
10-May	1030	92	OIL	WASTE STARTUP	124.0	98.0	8	0.1
10-May	1137	94	OIL	LOW LOAD/O2/GPM	42.0	41.0	8	0.1
10-May	1408	96	OIL	LOW LOAD BASELINE	24.0	3.0	4	0.7
10-May	1452	97	OIL	LOAD INCREASE	12.0	2.6	4	0.3
10-May	1647	101	OIL	BASELINE OIL, MODERATE LOAD	15.0	4.4	5	0.3
10-May	1750	103	OIL	HIGH GPM/MODERATE LOAD	5.8	2.6	10	1.6
10-May	1831	104	OIL	MODERATE O2/HIGH GPM	0.3	0.9	1	1.3
10-May	1917	105	OIL	GPM TRANSIENTS	2.0	1.0	23	10.6
10-May	2012	107	OIL	START INVERTED SPRAY	14.0	3.3	37	2.7
10-May	2055	108	OIL	INVERTED SPRAY	7.6	1.0	29	4.0
10-May	2134	109	OIL	INVERTED SPRAY	4.9	0.3	67	15.7
10-May	2221	111	OIL	SOOTBLOW	8.8	2.7	144	16.0
10-May	2313	118	OIL	MIN. USABLE ATOM	2.5	33.0	164	12.8
11-May	0007	122	OIL	MIN. USABLE ATOM	4.5	1.7	145	31.0
11-May	1430	143	OIL	WASTE STARTUP	10.0	ND	3	0.3
11-May	1525	144	OIL	HIGH BASELINE	100.0	17.0	273	2.8
11-May	2033	1 TRAP VOST	OIL	REDUCED ATOM.	0.7	2.1	88	67.1
11-May	2118	1 TRAP VOST	OIL	SOOTBLOW	ND	1.4	56	124.1

+ Numbers indicate MiniVOST analysis

* As chlorine basis

TABLE 4.33

PIC AND POHC EMISSIONS AT SITE M

TEST	CONDITIONS	TOTAL POHC (ug/s)	Chlorinated PICs (ug/s)	PIC/POHC RATIO
MV-1	Baseline, low air, no oil	--	--	--
MV-2	Waste oil lightoff, low air	--	691.4	--
MV-3	Baseline, normal load & air	--	--	--
MV-4	MCB spike start	940.4	567.1	0.6
MV-5	Low air, smoky	2145.5	1863.9	0.9
MV-6	Low air, atomization off	1056.1	311.6	0.3
MV-7	Low load, no waste gas	3142.0	9631.4	3.1
MV-8	Smoky, low load & air, no waste gas	--	0.0	--
MV-9	Max fan capacity	13.0	1443.7	111.3
MV-10	Max fan capacity	--	480.9	--
MV-11	Low air, hazy	30.3	1315.9	43.5
MV-12	Low air, hazy	8.8	1537.4	175.7
MV-13	High air	7.2	673.2	93.6
MV-14	Sootblowing	7.3	1568.4	214.4
MV-15	Sootblowing	2.2	2942.3	1365.3
MV-16	Residual POHC & PIC check, no oil	--	234.0	--
MV-17	Oil lightoff, low load	189.4	233.2	1.2
MV-18	Low load	188.7	305.5	1.6
MV-19	Low load, low air	121.2	122.5	1.0
MV-20	High oil firing	101.9	279.4	2.7
MV-21	High oil firing, smoky, low air	191.6	285.3	1.5
MV-22	High oil firing, smoky, low air	314.5	856.6	2.7
MV-23	Smoky 2 top burners only	119.1	227.9	1.9
MV-24	Residual POHC & PIC check, no oil	--	126.3	--
MV-25	Residual POHC & PIC check, no oil	--	66.4	--
MV-26	Low load, lightoff, smoky	229.4	385.6	1.7
MV-27	Baseline with MCB, CC14, TCB	70.5	434.3	6.2
MV-28	High air	60.8	224.0	3.7
MV-29	Sootblowing	--	296.2	--
MV-30	Sootblowing	449.3	260.6	0.6
MV-31	Oil lightoff, Residual POHC & PIC ck	--	672.8	--
MV-32	Normal load and air	308.3	268.3	0.9
MV-33	Normal load and air	440.8	367.8	0.8
MV-34	High CC14	436.3	539.0	1.2
MV-35	High CC14	457.2	209.6	0.5
MV-36	Low CC14	544.0	184.8	0.3
MV-37	Low CC14	205.6	172.9	0.8
MV-38	High CC14	120.6	232.4	1.9
MV-39	Residual POHC & PIC check	--	168.5	--

TABLE 4.33--Continued

TEST	CONDITIONS	TOTAL POHC (ug/s)	Chlorinated PICs (ug/s)	PIC/POHC RATIO
MV-40	Residual POHC & PIC check	--	632.6	--
MV-41	Residual POHC & PIC check, no oil	--	642.4	--
MV-42	Unsteady oil flow, low load	252.0	2394.8	9.5
MV-43	High TCB	339.6	642.1	1.9
MV-44	High TCB	--	343.2	--
MV-45	High TCB, low air, smoky	765.6	515.9	0.7
MV-46	Reduced TCB, low air, hazy	79.6	578.8	7.3
MV-47	Reduced TCB, low air, hazy	79.6	716.5	9.0
MV-48	Sootblowing	266.7	676.7	2.5
MV-49	Residual POHC & PIC check, no oil	--	3.9	--
MV-50	High air, no spikes	--	1518.7	--
MV-51	High air, high MCB & CCl4	290.4	104.2	0.4
MV-52	Low air, hazy stack	180.0	975.5	5.4
MV-53	Low air, smoky, high MCB & CCl4	163.5	157.4	1.0
MV-54	High MCB & CCl4	90.6	52.9	0.6
MV-55	High MCB & CCl4	103.6	263.5	2.5
FV-1	MCB spike start	39.7	89.4	2.3
FV-2	Low air atomization off	--	426.0	--
FV-3	Low air, hazy	55.7	126.3	2.3
FV-4	Low load, low air	153.8	163.1	1.1
FV-5	Low load, lightoff, smoky	31.1	180.4	5.8
FV-6A	High air	120.8	438.5	3.6
FV-6B	High CCl4	564.7	750.9	1.3
FV-7	High CCl4	859.8	1283.7	1.5
FV-8	Residual POHC & PIC check	--	713.8	--
FV-9	Usteady oil flow, low load	252.0	47.2	0.2
FV-10	High TCB, low air, smoky	765.6	3058.5	4.0
FV-11	High air, high MCB & CCl4	244.2	596.3	2.4
FV-12	Low air, hazy	189.5	226.9	1.2
FV-13	Low air, high smoke, high MCB & CCl4	172.3	594.0	3.4

TABLE 4.34

POHC AND PIC EMISSIONS AT SITE N

Test condition	POHC type	POHC feedrate (g/sec)	POHC Emission rate (µg/dscm)	POHC Emission rate (µg/sec)	DRE (percent)	PIC Emissions[a] (µg/dscm Chlorinated	PIC Emissions[a] (µg/dscm Nonchlorinated
1	--	--	--	--	--	25 to 220 (93)	4800
2	--	--	--	--	--	20 to 29 (25)	NA
3	--	--	--	--	--	20 to 36 (28)	NA
4	--	--	--	--	--	17 to 22 (20)	NA
5	--	--	--	--	--	36 to 200 (97)	780
6	TCE	17.62	1.0 to 2.3 (1.8)	17 to 38 (29)	99.9994	41 to 73 (61)	1180
7	TCB	19.72	0.9	17	99.99991	11 to 19 (15)	NA
8	TCE	18.55	2.0 to 8.2 (4.9)	32 to 130 (78)	99.9996	57 to 130 (90)	460
8A	TCE	40.80	0.6 to 0.8 (0.8)	10 to 13 (12)	99.99998	39 to 40 (40)	NA
9	TCE	21.33	ND	ND	100	6.4 to 7.0 (6.7)	NA
10	TCE	20.40	0.4 to 0.6 (0.6)	5 to 8 (7)	99.99997	5.3 to 88 (41)	4.7
12	TCB	22.68	9.6	120	99.9995	91 to 115 (100)	NA
13	TCB	20.71	3.4	59	99.9997	12 to 18 (15)	NA
14	TCE	19.47	0.20	2.8	100	31 to 45 (38)	NA
14A	--	--	--	--	--	127	NA
15	TCB	19.72	2.0	32	99.9998	57	NA
16	TCB	20.71	4.7	74	99.9996	7.3 to 23 (15)	NA
17	--	--	--	--	--	29 to 1300 (450)	2900

NA -- Not available. Sampling and analysis not performed or loss of data due to analytical problems.

ND -- Not detected.

[a] RCRA -- listed Appendix VIII, Volatile and Semivolatile Compounds -- nonchlorinated are primarily benzene, toluene, naphthalene, and phthalates.

[b] Number in parenthesis is the arithmetic average of multiple test measurements.

Unburned Hydrocarbon Emissions

The concentration of hydrocarbons was measured during most of the tests. Total unburned hydrocarbons (TUHC) was measured at seven sites; C_1-C_6 hydrocarbons were measured at five sites. Both measurements were made at one site - Site G. The former, TUHC measurements, were made continuously by a FID. Filtered stack gas is drawn through the FID which has been calibrated with a specific hydrocarbon (methane and propane are commonly used). The C_1-C_6 procedure is a GC analysis of integrated bag samples of the stack gas. The GC (also with an FID), is calibrated with five to seven different low molecular weight alkanes. The results of the two methods are not directly comparable. At Site G (Table 4.35), for example, the hydrocarbon emission rates estimated by the C_1-C_6 procedure were higher than the TUHC results by a factor of 30. The C_1-C_6 procedure is more rigorous and should produce better data.

The unburned hydrocarbon emission rates summarized for the steady operation tests are approximate (±100%), but precise enough for the present discussion. They, plus the carbon monoxide that is emitted at approximately the same rate, are the products of incomplete combustion of the organic fuel. The most predominate species emitted is three-carbon (propane) which is not a significant component of No. 6 (or distillate) fuel oil. It is noted that the DRE of the fuel is, except for Site E, greater than 99.9%.

During the parametric testing TUHC was measured continuously by the FID method described above. An attempt was made at Site M to determine if correlations exist between PIC emissions and TUHC, and between the POHC emissions and TUHC. There appeared to be a slight increase in PIC and POHC emissions as the TUHC emissions increased. The correlation is weak, however (least squares correlation coefficient of 0.21), and more data is needed to substantiate this trend.

Chloride Emissions

The emission rate of chloride was measured during most tests by drawing sample gas through liquid filled impingers. The impinger solution was variable (there is no reference method) but should be unimportant since HCl is very soluble in water at room temperature. The various attempts to perform mass balances on the chlorine in the fuel streams were unsuccessful. In general, the measured chloride emission exceeded the measured chlorine input by 25%. The exhaust gas chlorine mass flow rate ranged from 69 to 168% of the fuel chlorine mass flow rate.

The method used by the contractors to determine the amount of chlorine in the fuel and waste fuel samples was ASTM-D808 or a procedure similar to it. This procedure consists of ignition of the sample in a Parr bomb that contains enough water to dissolve the resulting HCl. The chlorine content of the solution was determined either by classical wet chemical titration or by specific ion electrode.

Test Methods for Evaluating Solid Waste, Physical/Chemical Methods (SW-846) contains no procedure for measurement of the chlorine content of oil and waste oil. Persons in the Studies and Methods Branch (EPA/OSW/DC) recommend that Method 9020 (for organic halides in water and wastewater) be

TABLE 4.35

SUMMARY OF UNBURNED HYDROCARBON EMISSIONS
(NONPARAMETRIC TESTING)

Site	Fuel Plus Waste Feed Rate (gm/sec)	Emission Rate (mg/sec)	Fuel DRE (%)	$\frac{\text{TUHC}}{\text{Fuel}} \times 100$	Emission Rate (mg/sec)	Fuel DRE (%)	$\frac{C_1-C_6}{\text{Fuel}} \times 100$
C	525	<25	>99.995	0.005	NM	------	----
D (Hi Load)	718	NM[a]	------	-----	356	99.950	0.05
D (Lo Load)	346	NM	------	-----	300	99.913	0.09
E	489	NM	------	-----	1606	99.725	0.27
F	240	1.19	99.995	0.005	NM	------	----
G	247	2.95	99.999	0.001	91.6	99.963	0.04
I	264	21.8	99.992	0.008	NM	------	----
O	115	NM	------	-----	<28.5	>99.975	<0.002

[a] Not measured.

used). This procedure requires pyrolysis or organic material followed by microcoulometric titration of the liberated halides. It is not known whether the two methods give comparable results, nor has it been demonstrated that SW-846 Method 9020 is applicable to fuel and waste fuel samples.

A methods development effort is needed to standardize these procedures and to develop quality assurance criteria for them. The observed weaknesses do not preclude use of the data for this project, however. The exhaust gas measurement of HCl emissions gives the higher estimated emission rate so it is recommended that this (conservative) estimate be used to assess the impacts of chloride emissions.

The chloride emission rate data, presented in Table 4.36, are based on the exhaust gas measurements. They range from 0.45 to 14.53 grams/second (3.5 to 115.3 lb/hr) depending upon the size of the boiler and the percent chlorine in the fuel. Site M was a relatively small boiler that was burning a high chlorine content (approximately 12.5% Cl) fuel. Site D was a relatively large boiler burning a low chlorine content fuel.

Particle Emissions

Measurements of the emission rates of particles were made at only five of the sites. The measurements were all done with the MM5 procedure, which is not an EPA reference method. The results are useful estimates of the particle emission rates but cannot be considered highly accurate. The results are summarized for all sites (except Site N which are presented in Table 4.38) in Table 4.37. The available data are not sufficient to allow assessment of the impact of co-firing hazardous waste on the emission of particles by boilers.

Particulate emissions were measured at Site N (parametric tests) at the inlet and outlet of a baghouse to calculate particulate collection efficiency. Significant variation in the pariculate emissions and the baghouse collection efficiency was observed. The fly ash control system consists of a mechanical collector in series with a baghouse. The baghouse typically treats only 70% of the flue gas from the collector. The other 30% is bypassed to the stack. During the tests the bypass valve was classed resulting in baghouse filtering of all the flue gas. This valve positioning resulted in the baghouse operating at rates in excess of the design level which could account for the variation in collection efficiency and the poorer than anticipated collection performance.

The large variation in particulate emissions reported for the baghouse inlet is not only a result of changes in the boiler but also reflects changes in the performance of the upstream (of the baghouse) mechanical collector. This device is affected by changes in flue gas flow rate and particulate loading.

Grain loadings calculated from Table 4.38 range from 0.110 to 0.776 grain/dscf at the baghouse inlet and from 0.014 to 0.031 grains/dscf at the outlet.

TABLE 4.36

SUMMARY OF CHLORIDE EMISSION RESULTS

Site	Chloride Average Recovery (I_{out}/I_{in})	Coefficient of Variance (percent)	Average Chloride Emission During Co-Firing (as HCl) gm/sec	Average Chloride Emission During Co-Firing (as HCl) lb/hr
A	NM	----	NM	NM
B	NM	----	NM	NM
C	NM	----	NM	NM
D	1.11	47.0	14.53	115.3
E	.818	76.8	6.18	49.1
F	1.68	49.7	2.87	22.8
G[a]	1.52	3.8	0.448	3.52
H	--- Report Not Available ---			
I	1.27	10.9	5.18	41.1
J	0.69	41.0	0.51	4.03
K	0.886	37.3	3.41	27.1
L	0.511	55.9	0.94	7.672
M	0.389	45.2	2.48	19.7
N	0.728	36.2	6.52	51.8
O	1.62	23.0	12.98	103.1

NM - Not measured.

[a] Source was equipped with two-stage scrubber.

TABLE 4.37

SUMMARY OF PARTICLE EMISSION RESULTS
SITES A-M, AND O

Site	Particle Emission Rates[a]				
	gm/sec	lb/hr	ng/J	lb/10^6 Btu	gr/dscf[b]
A			-- Not Measured --		
B			-- Not Measured --		
C			-- Not Measured --		
D					
Baseline (oil)	630	5.00	25.0	0.058	0.026
Average Co-Fired	785	6.22	33.2	0.077	0.039
E					
Baseline (oil)	304	2.41	13.9	0.032	0.105
Average Co-Fired (oil)	441	3.50	18.3	0.042	0.152
Average Co-Fired (gas)	157	1.25	9.4	0.022	0.068
F					
Baseline (oil)	0.0807	0.641	7.61	0.0177	0.009
Average Co-Fired	0.408	3.24	40.77	0.095	0.042
G					
100% Waste Fuel	960	3.36	86.9	0.202	0.099
H			-- Not Measured --		
I			-- Not Measured --		
J			-- Not Measured --		
L			-- Not Measured --		
M			-- Not Measured --		
O			-- Not Measured --		

[a] These results are based upon Modified Method 5 (MM5) samples. They should be considered to be approximate.

[b] Corrected to 7% O_2 as required by incinerator regulation.

FIGURE 4.38

PARTICULATE MASS EMISSIONS AND BAGHOUSE COLLECTION EFFICIENCY SITE N

Test condition	Test description	Baghouse inlet			Baghouse outlet			Baghouse collection efficiency (percent)
		Gas temperature (°F)	Gas flowrate (10^3 dscfm)	Emissions (lb/hr)	Gas temperature (°F)	Gas flowrate (10^3 dscfm)	Emissions (lb/hr)	
1	High load baseline coal only	376	34.75	116.0	359	38.47	10.25	91.2
2	High load baseline coal and sludge	386	35.84	108.2	367	39.24	6.92	93.6
3	Low load coal only	355	26.34	33.32	319	30.42	5.37	83.9
4	Low load coal and sludge	363	25.14	34.88	325	29.25	5.78	83.4
5	High load coal and oil	397	34.66	92.75	--	--	--	--
6	High load coal sludge and TCE	382	34.92	245.4	--	--	--	--
7	High load coal sledge and TCE	386	40.46	265.6	--	--	--	--
9	Low load, low air coal, sludge and TCE	347	27.20	110.00	317	26.87	3.19	97.1
12	Low load, coal, oil and TCE	353	26.16	35.90	324	31.13	6.56	81.7
13	Low load, high air coal, oil, and TCB	370	36.96	75.66	--	--	--	--
14	Low load, coal, oil and TCE	353	29.93	28.02	323	30.48	6.57	76.6
15[a]	High load, coal, oil TCB and metals	375	33.55	46.73	356	40.08	9.41	79.9
16	Low load, high air coal, sludge, TCB, and metals	367	33.49	48.96	337	37.86	4.61	90.6
17	High load, baseline coal and sludge	372	34.64	96.30	--	--	--	--

[a] Test aborted before all traverse points were sampled.

Metals Emissions During Co-Firing

Sampling and analysis of the metals content of the waste fuels and stack emissions was not a primary object of this test program. It was decided that sufficient information about the behavior of various fuel-contained metallic elements in boilers already existed. Section 3 of this document contains a discussion of the volatility and small particle enrichment of the metals in fuels. The limited aim of metals sampling during this program was to confirm that the reported partitioning was applicable to the case of hazardous waste combustion. Thus, the emission rates of hazardous trace metals were measured at only four of the sites.

Of the eight metals measured at one of these sites (Ag, As, Ba, Cd, Cr, Hg, Pb, and Se) only two were found in higher concentrations during the co-firing tests than during the baseline test. Mercury was higher by 180 picograms per cubic meter and lead by 80 picograms per cubic meter. Only the concentration of selenium exceeded 1 microgram per cubic meter. All others were less than 400 picograms per cubic meter.

Fourteen metals were measured in the feed streams and exhaust gases at the second site. There was no statistical difference between the baseline run stack gas concentration and the co-fired run baseline concentration for six of these. Increased stack gas concentrations for seven of the other eight corresponded to increased fuel concentrations. The emitted concentrations of the more hazardous of these metals is given below.

CONCENTRATION OF HAZARDOUS METALS EMITTED FROM SITE K

	Exhaust Gas Concentration (ug/m^3)	
Metal	Co-Fired	Baseline
Arsenic	13.7	3.0
Cadmium	114.5	71.2
Chromium	64.4	46.8
Cobalt	33.3	18.7
Mercury	0.9	0.3
Lead	1050.8	455.8
Antimony	4.6	1.8

The stack gas contained approximately 70% of the chromium in the combined fuel. The partitioning of metals between fly ash and boiler ash, as discussed in Section 3, varies according to the vapor pressure of the metal and its compounds at the boiler flame temperature. The more volatile elements measured during this test (As, Cd, Pb, and Sb), demonstrate this effect.

In Site N testing the oil (test condition 15) and sludge (test condition 16) were spiked with chromium and lead to investigate the partitioning of these metals between the bottom ash and the fly ash. To qualify the portion in the fly ash, the metals were measured in the flue gas at the baghouse inlet and in the mechancial collector ash. Results of these measurements are summarized below.

	Test Condition	Bottom Ash g/hr		Fly Ash g/hr		Inlet/ Outlet	
		Cr	Pb	Cr	Pb	Cr	Pb
1	Baseline Coal	0.73	0.73	9.32	16.1	2.92	0.00
2	Baseline Coal and Sludge	0.75	0.66	8.99	18.54	2.94	0.00
15	Coal Co-fired with Metal Spiked Oil	0.73	0.73	88.37	207.22	2.58	1.15
16	Coal Co-fired with Metal Spiked Sludge	0.33	0.24	30.45	58.67	7.45	4.07

The chromium results are considered inconclusive because of the poor closure of the material balance (less then 40% of chromium unaccounted for). The single run (test condition 15) in which a good mass balance closure was obtained, indicates that lead, which is a volatile metal, can be expected to be emitted in the flue gases during combustion of lead-containing wastes.

Regulatory Implications of the Test Burn Data

Test burns were conducted at several types and sizes of industrial boilers. They were:

Boiler Type	Size Range of Tested Boilers (MMBtu/hr)
Fire Tube	8.4 - 40
Package Water Tube	10 - 110
Field Erected Water Tube	230 - 350
Converted Coal Stoker	22 - 90
Coal Stoker Burning Wood Waste	10
Pulverized Coal Tangential Fired	250
Coal Stoker Burning Coal and Sludge	200

Only one boiler type, the coal stoker burning wood waste, failed to destroy at least 99.99% of the hazardous material that were co-fired. This boiler exhibited other signs of poor combustion efficiency; e.g., high (1250 ppm) carbon monoxide concentration in the flue gas and low (63%) thermal efficiency. Additional testing is needed to demonstrate that this type of boiler can effectively destroy hazardous waste.

The hazardous waste fuels burned during these tests were atomized into the boiler combustion chambers at all sites but one. This one was the coal stoker burning wood waste. The lack of waste atomization could have contributed to the poor performance of this unit. It is deemed wise to specify that atomizing guns be provided for any hazardous wastes to be burned. In addition, one other boiler (Site F - a multiburner water wall boiler) failed to destroy 99.99% of the hazardous waste. This failure was attributed to improper orientation of the waste burner gun relative to the boiler flame that caused flame instability, some smoking, and formation of coke on the burner. Engineering specifications on the size, location, and orientation of the waste atomizing gun should be developed to assure adequate destruction of hazardous wastes.

The percent of total fuel comprised of hazardous waste materials ranged from a low of 8% to a high of 52% for the boilers co-firing wastes. No effect of waste fraction on DRE was observed. One boiler, a fire-tube boiler that was specially modified for the purpose of burning hazardous waste, was able to destroy more than 99.99% of the hazardous components while burning 100% waste material. This was a special circumstance that should not be considered representative of boilers in general.

The minimum heat content of the water materials burned during these tests was 8700 Btu/lb. This, co-incidentally, was approximately the heat content of the waste that was successfully destroyed by the specially modified boiler firing without auxillary fuel. The data support the conclusion that adequate DRE will be attained when the hazardous material has a heat content of 8,700 Btu/lb or more.

Attempts to correlate DRE with operating conditions (e.g., CO, O_2) failed. The DRE of the hazardous components did not vary significantly and no correlations were possible even though combustion parameters were varied during some tests over a wide range of operating conditions.

No correlation of PIC emission with carbon monoxide was observed during the testing either. However, below a carbon monoxide concentration of about 100 ppm the PIC emissions observed during the burning of hazardous waste were approximately the same order of magnitude as those observed during the burning of conventional fossil fuels (baseline conditions).

The minimum boiler steam load (as a percent of boiler capacity) tested was 25%. The maximum load tested was 100%. DRE of hazardous constituents in excess of 99.99% was demonstrated at all loads. The data support the conclusion that a boiler may be operated within this range while maintaining 99.99% DRE.

MODIFYING BOILER SYSTEMS TO BURN HAZARDOUS WASTE

In order to fire hazardous waste, certain modifications to the boiler system may be necessary. Some wastes may need to be pretreated before they can effectively be used as fuel. Also, burner guns and combustion controls may have to be adopted to handle the wastes. In addition to these changes, certain modifications may be required to comply with requirements adopted as part of a regulatory option. For example, waste feed, oxygen and carbon monoxide monitoring is being considered to ensure that adequate destruction of POHCs is achieved in these boilers. This subsection describes the rationale and the types of equipment used for these modifications.

Waste Pretreatment

Some hazardous waste streams are pretreated to improve their suitability for firing in industrial boilers. An OSW sponsored mail survey of approximately 250 industrial boiler operators burning hazardous wastes revealed that four types of pretreatment are common:

- Blending of the waste stream with a conventional fuel or another waste stream
- Heating the waste to reduce the viscosity (thermal treatment)
- Dewatering
- Solids removal

These four types of pretreatment are described below. Based on information obtained from a follow-up telephone survey of 11 respondents to the OSW survey, other types of pretreatment are expected to be rare.

Blending

In any facility, the quantity and composition of waste produced will likely vary with time. Blending helps to normalize fluctuations in composition, heating value, and viscosity of waste fuel flowing to the boiler. This reduces the potential for boiler upset and assures high efficiency in destruction of hazardous wastes. Blending may also be the only way to reduce emission rates of ash, metals, chloride, and similar contaminants, to permissible levels.

Tests for incompatibility are performed before components are mixed on a large scale to assure that no unexpected events occur. Several possible upsets are:

- Release of dissolved water or formation of two organic phases
- Precipitation of solid materials
- Release of gases or fumes
- Sudden release of heat

It is theoretically possible to continuously blend wastes, and run the blend to a boiler. However, the wide variety of wastes which might be expected at any given facility and the unexpected problems which might arise from mixing varying components indicate that tank blending is the better mixing technique. The technology is simple, requiring only storage tanks equipped with top- or side-entering agitators. The wastes are pumped to the tank and agitated for several hours. After testing, the mixture can be pumped to the boiler.

At least three mixing tanks should be provided, each equipped with an agitator. One tank will be filling, one filled and on standby, and one emptying to the boiler, each tank sized for at least eight hours of burning capacity. Additional tanks may be required to store wastes with high metals, ash, chlorine, or other contaminant levels. The contents of these special tanks would be blended down in the working tanks. Blending may be combined with settling, in which case the components would be introduced into cone bottom tanks, agitated for blending, then allowed to remain quiescent to allow separation of the phases.

Each tank should be equipped with level indicators, and with high and low level alarms. These will assure that the tanks are neither overfilled nor pumped dry.

Thermal Treatment

Although waste fuels may be heated to assist in breaking emulsions or to keep mixtures in a single phase, the primary reason for heating waste fuel is to maintain viscosities at desirable levels. Very high viscosity materials may only be pumped with difficulty, so it is generally considered desirable to keep viscosity below 10,000 SSU.

Heavy fuels (e.g., No. 6 fuel oil, bunker fuel and tars) are generally stored in insulated tanks equipped with tank heaters. This proven technology is directly applicable to waste fuels. The storage tank is usually insulated with a two to three inch layer of suitable insulation and heated with a side-mounted steam heat exchanger or steam coils installed near the floor. A gear pump, designed for the expected temperature and viscosity is usually used to transfer the fuel. The pump and pipe are insulated and heat traced to prevent fuel from cooling in the lines. The main fuel pipe runs past the boiler, and recirculates to the storage tank. A branch, as short as possible, carries fuel to each burner.

In addition, it is necessary to regulate fuel viscosity at the burner. Although some burners are capable of handling high viscosity materials (Reference 2), maximum viscosities as low as 100 SSU have been cited by one supplier (Reference 3) and 250 SSU by another (Reference 4). As fuel viscosity at the burner increases, the likelihood of incomplete combustion and stack opacity increases, so 750 SSU has been selected as the maximum desirable viscosity at the burner for this study. This can usually be achieved by installing a steam or electric heat exchanger adjacent to the boiler. Figure 4.39 is a block diagram of a typical installation at the boiler. The storage tank and tank heater are not shown. Temperature of the oil discharged from the boiler is usually controlled, but if characteristics are variable, the fuel should be tested frequently to determine the temperature which will yield the proper viscosity.

The waste fuel may be heated to 500°F (260°C). The temperature limit is set by the possibility of charring and cracking the liquid stream, and of volatilizing low boiling components.

Before an unknown waste is heated, small samples should be tested to be sure that no undesirable reactions occur. These may include:

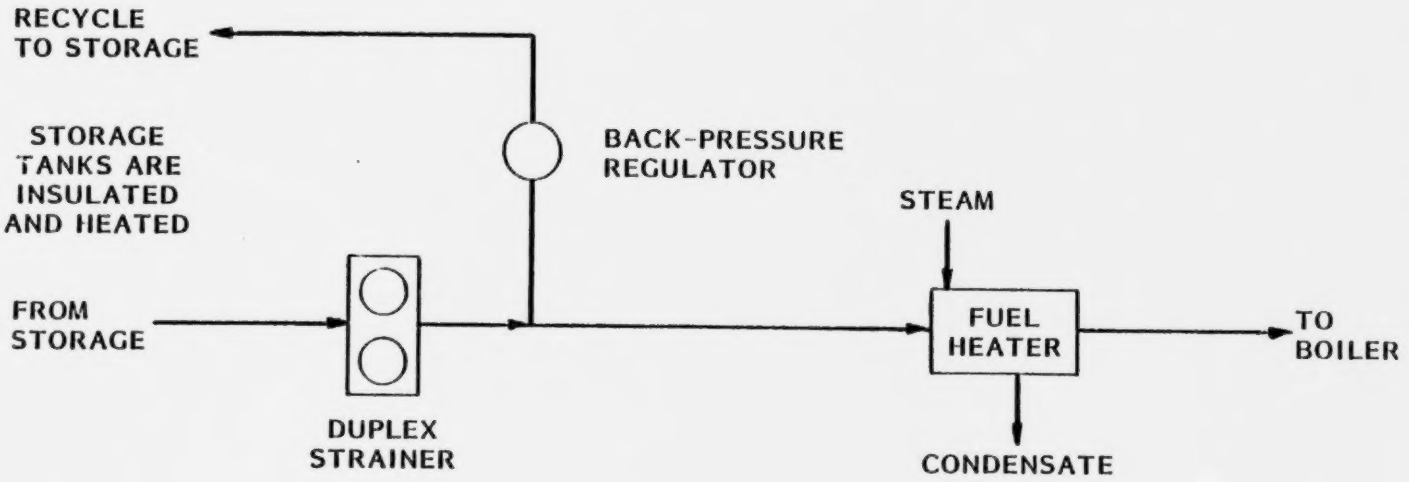
- Separation of phases
- Coagulation of components
- Release of vapors
- Explosive reactions
- Increased danger of ignition during storage
- Cracking

Dewatering

Water in a liquid waste fuel impacts a boiler in three ways. Free or undissolved water in a waste stream almost invariably causes burner pulsation, and frequently leads to flame failure with concomittant burner shutdown. The problem is addressed in detail in Reference 5. Water also tends to lower the

FIGURE 4.39

BLOCK DIAGRAM, EQUIPMENT FOR THERMAL TREATMENT


RECYCLE TO STORAGE
STORAGE TANKS ARE INSULATED AND HEATED
FROM STORAGE
DUPLEX STRAINER
BACK-PRESSURE REGULATOR
STEAM
FUEL HEATER
CONDENSATE
TO BOILER

heating value of the organic waste fraction since a portion of the heat generated by its combustion is consumed in vaporizing and heating the moisture up to the boiler discharge temperature. A third effect of water in a waste stream is to increase the moisture content of the combustion gas which lowers its dew point. This will increase the potential for acid corrosion in the flue gas handling equipment.

One large facility limits waste fuels to single phase mixtures containing less than 15% water (Reference 6). However, because few facilities will have the sophistication to handle this level of water, this discussion is based on a maximum water content of 5%.

Blending and decanting are the means being used for reducing the water content of waste streams fired in industrial boilers. Blending, which was described above, can be used to lower the water concentration when the water and organic fraction of the waste stream are highly miscible. Decanting is used to remove undissolved or free water from a waste stream and is described in this subsection. It does not remove water dissolved in the organic waste fraction which is governed by solubility limits.

Decanting is a physical separation process where the waste is allowed to stand until the water and organic phases form two separate layers. Each layer is then mechanically drawn off. The process may either be a batch or continuous operation.

Equipment for decanting is relatively simple. One or more common storage tanks are often used for dewatering waste streams fired in industrial boilers. For a continuous operation requiring a long detention time to effect the separation, an arrangment like that shown in Figure 4.40 may be used. Three tanks are used to provide the long detention time. Each tank is alternatively used for receiving the water laden waste; holding the waste until the separation is achieved; and for a transfer tank from which the dewatered waste is pumped to the boiler. In the holding mode, the tank is used to provide a quiescent environment for the water to separate from the organic fraction, the tank detention time required depends on the properties of the waste and may be determined by periodically withdrawing samples from the tank if it is not known from past experience. Once the separation is achieved, the water is pumped to the sewer or the plant's wastewater treatment facility and the holding tank then becomes the transfer tank. The tank originally serving as the transfer tank becomes the new receiving tank and the original receiving tank becomes the new holding tank.

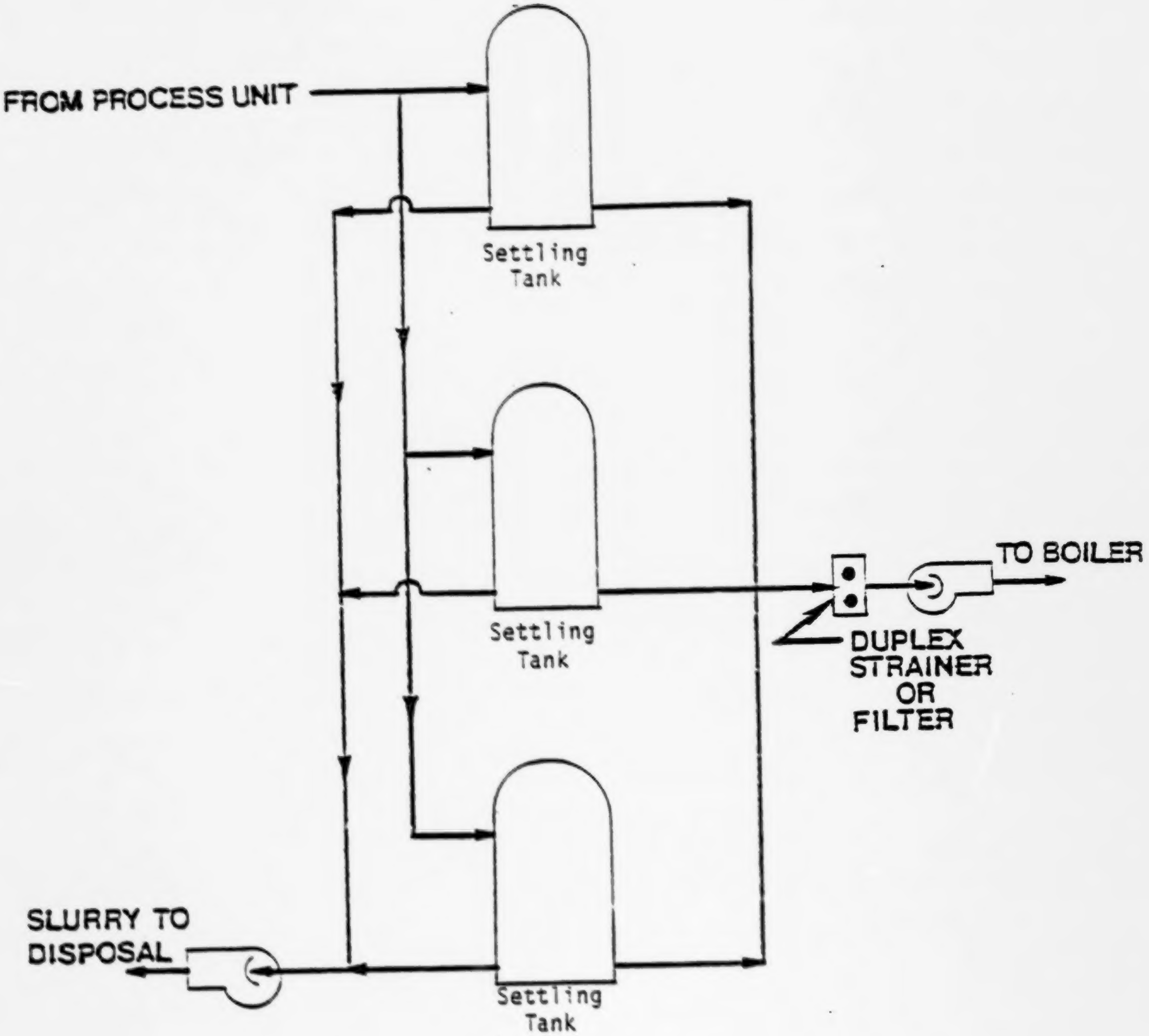
Solids Removal

Although almost any waste material that can be pumped can be used as a waste fuel, high solids materials cause significant operating problems:

- Burner gun plugging
- Abnormal burner gun fouling and abrasion
- Deposition in the fuel train
- Deposition on boiler heat transfer surfaces
- Increased particle emissions

FIGURE 4.40

TYPICAL SOLIDS REMOVAL SYSTEM


FROM PROCESS UNIT
Settling Tank
Settling Tank
TO BOILER
DUPLEX STRAINER OR FILTER
SLURRY TO DISPOSAL
Settling Tank

To minimize these deleterious effects, this discussion is based on a maximum of 5% solids in the waste fuel fed to the boiler. The more common processes used for removing solids from waste streams incinerable in industrial boilers include settling or sedimentation, straining or screening, and filtration. Settling is a physical separation process whereby particles suspended in a liquid are made to settle by means of gravitational and/or inertial forces acting on both the particles suspended in the liquid and the liquid itself. A variety of devices are used for this process. For the size streams incinerated in industrial boilers, one or more conical bottom tanks are used to provide the time and space for the solids to settle out. These sometimes have provisions to prevent the incoming stream from disturbing the settling solids.

In-line strainers consist of one or more mesh baskets housed in a vessel which may be one of a variety of geometric configurations. When the waste is passed through the strainer, the solid particles are trapped in the basket. Several strainer designs are commercially available, differing mainly in the cleaning approach. A duplex strainer which permits the cleaning of one basket while another is on-line is a common choice for this application.

Filtration is a physical process whereby the suspended particles are separated by forcing the fluid through a porous medium. As the fluid passes throught the porous medium, the suspended particles are trapped on the surface of the medium and/or within the body of the medium itself. A wide variety of filtration equipment is commercially avalaible to meet the many types of process requirements. A cartridge type filter may be used for solids removal from hazardous waste streams incinerated in industrial boilers. This device consists of a vessel containing one or more cartridges constructed from fiber glass, polyethylene, or other suitable materials through which the waste is forced to flow. The particles are collected on the cartridges. By using a duplex vessel containing two cartridges, either side may be shut down and serviced while the other side continues to filter.

A strainer or a filter may be used if the solids loading is sufficiently low that the cleaning frequency is not excessive. When the solids content is high, a combination of either settling and straining or settling and filtering is used. The overall process may be a batch or continuous operation. For a continuous operation requiring a long retention time, an arrangement like that shown in Figure 4.37 may be used. This arrangement is nearly indentical with that described above for dewatering. In this scheme, the wastes are pumped from a processing unit into one of three tanks, The three tanks are alternately used in a receiving mode, a holding mode to provide a quiescent environment for settling, and a transfer mode from which the supernatant waste is pumped to final solids removal by either screening or filtering. The collected solids are transferred from the bottom of the tanks into either a tank truck, drums, or carts for transport to safe disposal.

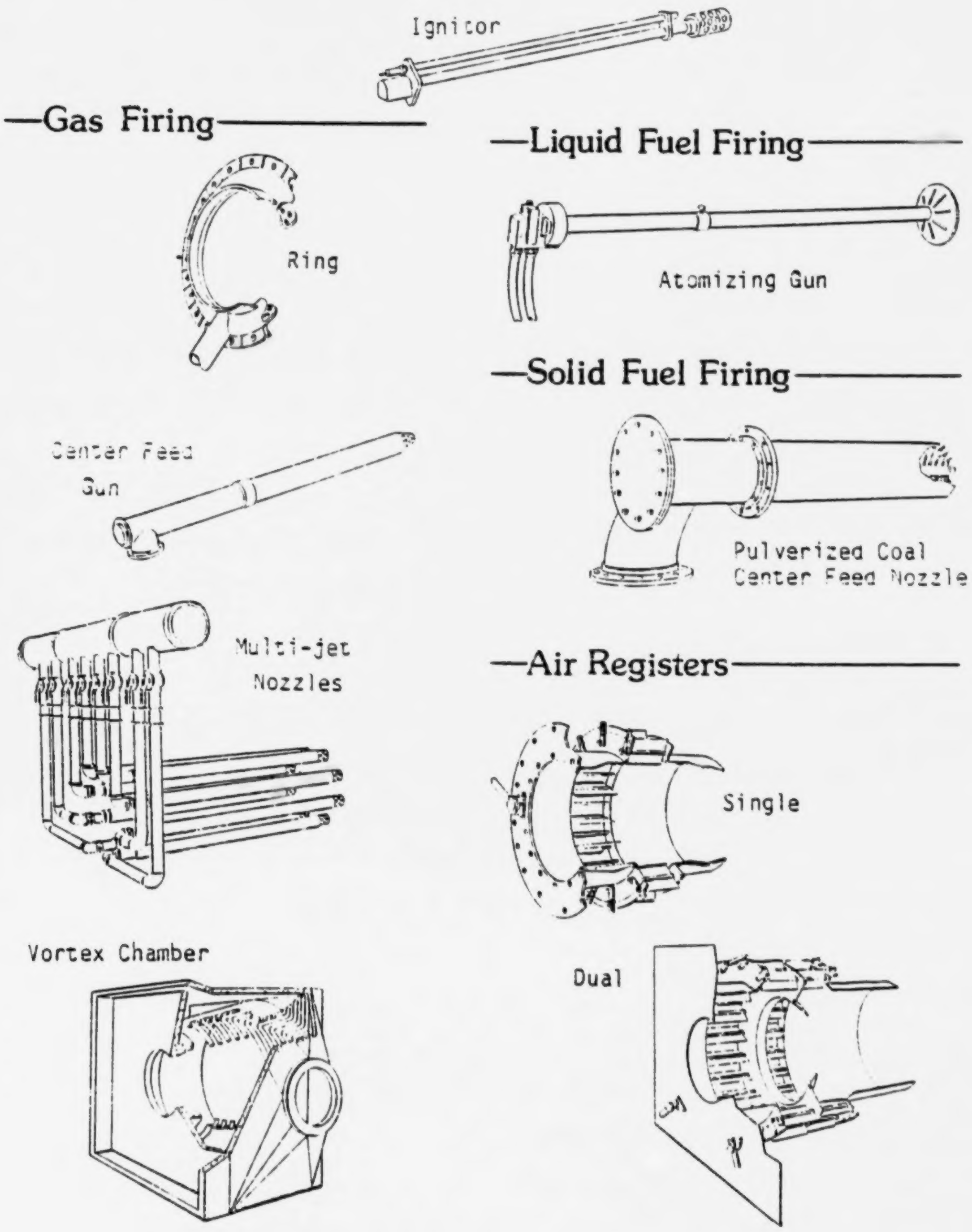
Burner Gun Assembly and Process Control Instrumentation

Burner Gun Assemblies

Burner gun assemblies are intended to provide intimate mixing of fuel and combustion air, assuring complete combustion using the minimum amount of air. Assemblies are available to burn combinations of gas, liquid, and solid

FIGURE 4.41

BURNER COMPONENTS


Ignitor
—Gas Firing
—Liquid Fuel Firing
Ring
Atomizing Gun
—Solid Fuel Firing
Center Feed Gun
Pulverized Coal Center Feed Nozzle
Multi-jet Nozzles
—Air Registers
Single
Vortex Chamber
Dual

fuels, or to burn two gas or liquid streams with another fuel. Although there are differences in design details, the following, based on Zurn Industries Equipment (Reference 7), is typical. Figure 4.41 shows basic burner components. The ignitor maintains a pilot flame, when necessary, to ignite the main stream of fuel. Three types of gas feed systems are shown, as well as a liquid fuel atomizing gun, and a solid fuel (pulverized coal) gun. The air registers act to control air flow and to direct the air providing intimate contact with fuel, and shaping the flame.

Figure 4.42 shows single fuel burner assemblies, and Figure 4.43 shows combination fuel burner assemblies.

Most boilers are equipped to burn one fuel at a time, although dual fuel burning is not unknown. If a boiler is to be dedicated to burn relatively high heating value waste fuels which can support combustion, modification might be as simple as replacing a burner nozzle (and resetting fuel:air flow rates). It is more common to have wastes which vary in heating value and water content. To assure good combustion of these wastes, it is good practice to equip the boiler with two guns, one burning conventional fuel, and the other burning waste fuel. Some furnaces are already equipped to burn two fuels, in which case only the burner would have to be replaced. Single fuel boilers would require more extensive modification, which might require replacing the entire burner assembly and modifying the end of the boiler or the burner ports. In any case, all boiler safety controls and interlocks must be maintained.

Burner maintenance and operating problems associated with waste combustion include pulsation and flameout, poor atomization, flame instability and smoke formation, abrasion and fouling, coking, premature ingnition, and corrosion. These problems usually occur when the waste contains significant levels of water and solids, or when the burner design is not compatible with the physical properties or combustion characteristics of the waste (Reference 5). Many of these problems can be solved by co-firing waste fuel with conventional fuel, but it is critically important that each burner be suited to the fuel being burned. A nozzle designed for high heating value gas such as LPG might not be suitable for burning medium heating value gas such as natural gas, and would certainly not be suitable for burning low heating value waste gas.

Burners for liquid waste fuel are sensitive to viscosity, solids content, and particle size of the fuel. Burners can be selected from the following five types (Reference 2).

- Rotary cup atomization
- Single-fluid pressure atomization
- Two-fluid, low pressure air atomization
- Two-fluid, high pressure air atomization
- Two-fluid, high pressure steam atomization

In air or steam atomizing burners, atomization can be accomplished internally, by impinging the gas and liquid stream inside the nozzle before spraying; externally, by impinging jets of gas and liquid outside the nozzle; or by sonic means. Sonic atomizers use compressed gas to create high frequency sound waves which are directed on the liquid stream. The liquid nozzle diam-

FIGURE 4.42

TYPICAL

SINGLE FUEL BURNER ASSEMBLIES

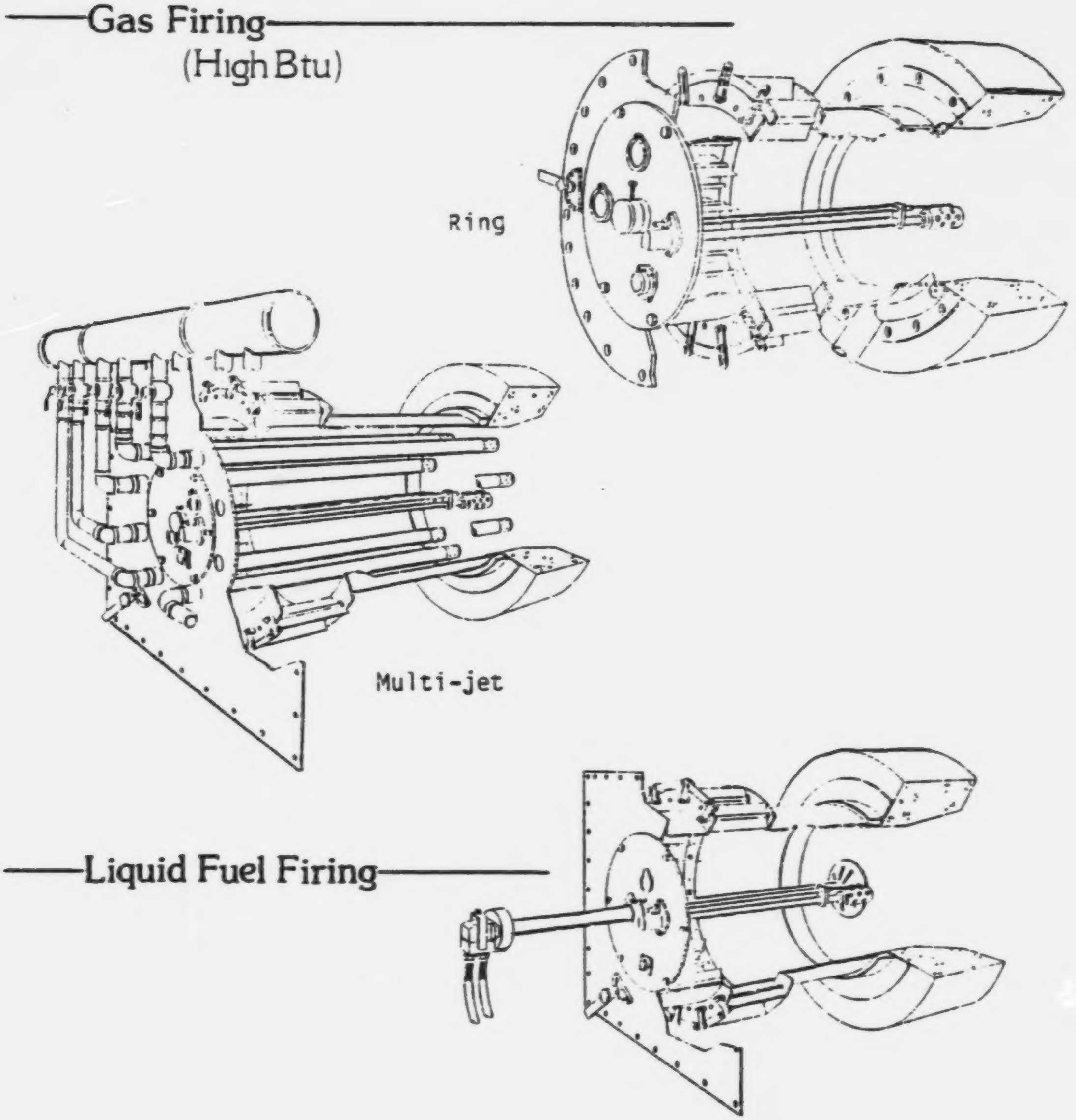
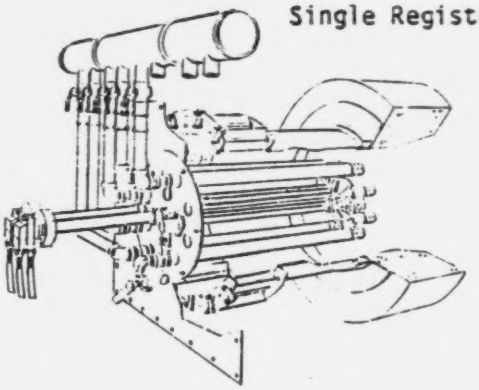

Gas Firing
(High Btu)
Ring
Multi-jet
Liquid Fuel Firing

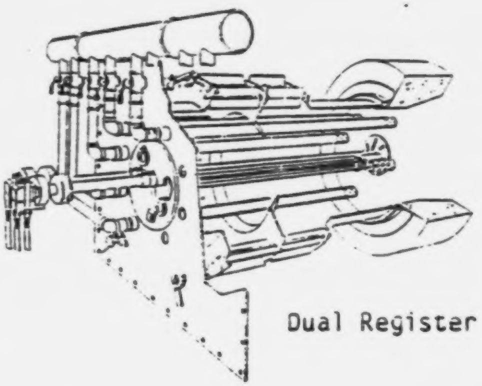
FIGURE 4.43

TYPICAL
COMBINATION FUEL BURNER ASSEMBLIES

Gas/Liquid Fuel Firing

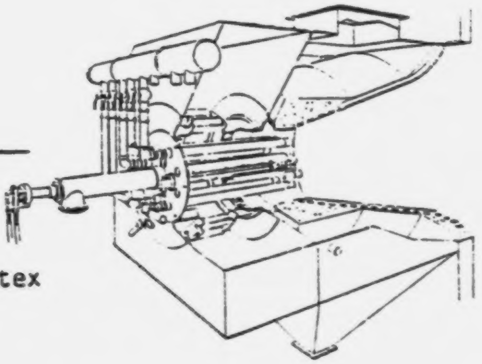


Single Register



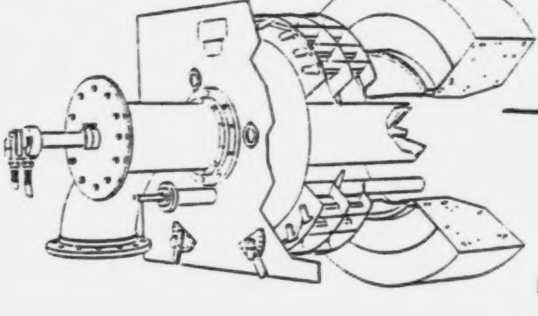
Dual Register

Multiple Gas/ Liquid Fuel Firing



Vortex

Solid/ Liquid Fuel Firing



Pulverized Coal Center-Feed

eter is relatively large, and little waste pressurization is required. Some slurries and liquids with relatively large particles can be handled without plugging problems.

The rotary cup consists of an open cup mounted on a hollow shaft. The cup is spun rapidly and liquid is admitted through the hollow shaft. A thin film of the liquid to be atomized is centrifugally torn from the lip of the cup and surface tension reforms it into droplets. To achieve conically shaped flames an annular high velocity jet of air (primary air) must be directed axially around the cup. If too little primary air is admitted, the fuel will impinge on the sides of the furnace. If too much primary air is admitted, the flame will not be stable and will be blown off the cup. For fixed firing rates, the proper adjustment can be found and the unit operated for long periods of time without cleaning. This requires little liquid pressurization and is ideal for atomizing liquids with relatively high solids content. Burner turndown is about 5:1 and capacities from 1 to 265 gal/hr, (1-280 cm^3/s) are available.

In single-fluid pressure atomizing nozzle burners, the liquid is given a swirl as it passes through an orifice with internal tangential guide slots. Moderate liquid pressures of 100-150 psi provide good atomization with low to moderate liquid viscosity. In the simplest form, the waste is fed directly to the nozzle, but turndown is limited to 2:5 to 3:1 since the degree of atomization drops rapidly with decrease in pressure. In a modified form involving a return flow of liquid, turndown up to 10:1 can be achieved.

When this type of atomization is used, secondary combustion air is generally introduced around the conical spray of droplets. Flames tend to be short, bushy, and of low velocity. Combustion tends to be slower as only secondary air is supplied and a larger combustion chamber is usually required.

Typical burner capacities are in the range of 10 to 105 gal/hr. Disadvantages of single-fluid pressure atomization are erosion of the burner orifice and a tendency toward pluggage with solids or liquid pyrolysis products, particularly in smaller sizes.

Two-fluid atomizing nozzles may be of the low pressure or high pressure variety, the latter being more common with high viscosity materials. In low pressure atomizers, air from blowers at pressures from 0.5 to 5 psig is used to aid atomization of the liquid. A viscous tar, heated to a viscosity of 75 to 90 SSU, requires air at a pressure of somewhat more than 1.5 psig, while a low viscosity or aqueous waste can be atomized with 0.5 psig air. The waste liquid is supplied at a pressure of 4.5-17.5 psig. Burner turndown ranges from 3:1 up to 6:1. Atomization air required varies from 370 to 1,000 ft^3/gal of waste liquid. Less air is required as atomizing pressure is increased. The flame is relatively short as up to 40% of the stoichiometric air may be admixed with the liquid in atomization.

High pressure two-fluid burners require compressed air or steam at pressures from 30 to 150 psig. Air consumption is from 80 to 210 ft^3/gal of waste, and steam requirements may be 2.1 to 4.2 lb/gal with careful control of the operation. Turndown is relatively poor (3:1 or 4:1) and considerable energy is employed for atomization. Since only a small fraction of stoichio-

TABLE 4.38

KINEMATIC VISCOSITY AND SOLIDS HANDLING LIMITATIONS OF VARIOUS ATOMIZATION TECHNQUES

(Reference 2)

Atomization Type	Maximum Kinematic Viscosity, SSU	Maximum Solids Mesh Size	Maximum Solids Concentration
Rotary cup	175 to 300	35 to 100	20%
Single-fluid pressure	150		Essentially 0
Internal low pressure air ($\leq$30 psi)	100		Essentially 0
External low pressure air	200 to 1,500	200 (depends on nozzle ID)	30% (depends on nozzle ID)
External high pressure air	150 to 5,000	100 to 200 (depends on nozzle ID)	70%
External high pressure steam	150 to 5,000	100 to 200 (depends on nozzle ID)	70%

metric air is used for atomization, flames tend to be relatively long. The major advantage of such burners is the ability to burn barely pumpable liquids without further viscosity reduction. Steam atomization also tends to reduce soot formation with wastes that would normally burn with a smokey flame.

Table 4.38 identifies typical kinematic viscosity and solids handling limitations for the various atomization techniques. These data are based on a survey of 14 burner manufacturers. In evaluating a specific boiler installation, however, the viscosity and solid content of the wastes should be compared with manufacturer specifications for the particular burner employed.

Whatever nozzle is selected, proper operation requires that the fuel arrive at the boiler at a reasonably constant viscosity.

Process Controls

Direct-connected controls are found on many packaged boilers. A single actuator-operated jackshaft (mechanical linkage) is used to open and close fuel and air valves (Reference 8). Typically, the jackshaft is positioned proportionally to boiler pressure, and linkages from the jackshaft regulate fuel supply valves and air dampers. If waste fuel is fed to a boiler of this type at a constant rate, limited to about 30% of the expected maximum heat load, and a conventional fuel is co-fired to take up the boiler swings, the direct-connected controls can be set up to fire without reaching reducing conditions or too much excess air in the stack gases (Reference 9). If wide swings in waste fuel heating value are expected, waste fuel flow might be limited to 5% of the boiler heat input, or an oxygen (excess air) analyzer might be installed in the stack gas duct. The output signal from the oxygen analyzer would be used to trim the position of the combustion air dampers, permitting firing of higher proportions of various heating value waste fuels.

Larger boilers are usually equipped with metering combustion control systems utilizing conventional instrumentation (Reference 10). The controls may be set up to fire single or multiple fuels, usually based on known heating values or air:fuel ratio requirements for each fuel (Reference 11) or on manually measured stack gas oxygen levels if waste fuel characteristics do not vary rapidly. The trend in conventional boiler instrumentation is toward a metering combustion control system with automatic adjustment of fuel: air ratio as a function of the target oxygen set point (Reference 10). This technique is directly applicable to burning waste fuel. Oxygen (excess air) control is necessary if high boiler efficiency is to be maintained. Automatic excess air trim systems which have been used succesfully in conventional boilers are available from several vendors for use on spreader stoker and packaged oil and gas boilers (Reference 12). These systems are reliable, requiring only about one hour a week of maintenance.

Carbon monoxide control is usually installed in response to regulatory requirements. An instrument senses carbon monoxide concentration in the stack gas and outputs a signal which may be used to reset the oxygen control set point. Alternatively, carbon monoxide concentration may be indicated and oxygen level adjusted manually.

Waste Feed Rate Monitoring

It may be necessary to restrict the flow of some highly toxic waste streams to a small fraction of the total fuel input to minimize the health risks associated with POHCs. If such restrictions are adopted, waste feed rate monitoring will be needed. Similarly, a trial burn may be advisable to demonstrate the capability of a boiler to achieve an adopted DRE. The quantity of POHC being fed to the boiler is needed for the DRE determination. This subsection describes some of the more useful flowmeters that may be used for this application. Detailed information on these and other flowmeters can be found in References 13-16.

The orifice meter, the positive displacement meter, and the flow tube meter are well suited for measuring the flow rate of liquid hazardous wastes. All three instruments are moderately inexpensive, are capable of the level of accuracy needed, are of relative simple design, and can be used over a large range of flows. The orifice meter and flow tube are differential pressure type flow measurement devices. This type device indirectly measures flow velocity by measuring a differential head (pressure) across an obstruction in the flow stream which increases the velocity of the fluid, thereby decreasing its pressure. Flow equations relate the velocity change to the pressure change. In an orifice meter, the differential pressure between the upstream and downstream sides of an orifice plate is measured with pressure taps on either side of the orifice plate.

One disadvantage of the orifice meter for use in this application is that suspended matter in the fluid may build up at the inside of the orifice plate (which will affect its accuracy). This can be avoided by keeping the solids content low. If it is not practical to reduce the solid content, the flow tube may be used. The flow tube is basically a venturi without the downstream recovery cone. Because it does not restrict the flow to the extent an orifice plate does, it is applicable to streams with appreciable solids content. It has a very constant discharge coefficient and is considered to be highly reliable. It is not as expensive as the venturi but considerably more expensive than the orifice meter.

The positive displacement type flowmeters have one or more moving parts positioned in the flow stream. The main devices are reciprocatory piston, rotary piston, rotary-vane meter, and nutating disk. Of these, the nutating disk meter is probably used in greater quantities than all the others combined. This device consists of a movable disk mounted on a concentric sphere. The disk is contained in a working chamber with spherical sidewalls and top and bottom surfaces that extend conically inward. The disk is restricted from rotating about its own axis by a radial partition that extends across the entire height of the working chamber. Each complete movement of the disk displaces a fixed volume of liquid. The liquid enters through an inlet port and fills the spaces above and below the disk, which fits closely and precisely in the measuring chamber. The advancing volume of liquid moves the piston in a nutating motion until the liquid discharges from the outlet port.

The vortex shedding meter works on the vortex shedding principle. In this device, the gas stream is forced past an obstruction (shedding bar) which sets up vortices (eddies) in the gas. These vortices cause vibrations in the shedding bar which are proportional to the flow. These vibrations are measured by a piezoelectric crystal which creates a voltage that is amplified and transmitted to an electronic scaling module. Advantages of these instruments include accuracy, no moving parts, and relative inexpensive price.

The turbine meter is a mechanical type measurement instrument. It operates on the turbine principle; i.e., the volume is measured by the movement of a wheel or turbine type of impeller. The blades of the turbine, which are positioned within a chamber, rotate as the gas passes through them. The rotor can be positioned so that it can be driven by radial or axial flow or a combination of both. The rotor's motion can directly drive a register. This device can be used to measure continuous high flow rates with minimum pressure loss.

Oxygen and Carbon Monoxide Monitoring

Some continuous indicator of the combustion performance of a boiler burning hazardous waste is essential. Combustion performance depends on operating parameters such as temperature, feed rate of waste, and air flow rate, but monitoring those operating parameters does not indicate what is actually being accomplished in the boiler in terms of the waste destruction. Monitoring oxygen and/or carbon monoxide levels in emissions does give a continuous assessment of the effectiveness of combustion. This point is supported by the industry trend to install O_2 and/or CO monitors as part of excess air trim systems to save fuel costs through increased combustion efficiency. CO monitoring is being required on hazardous waste incinerators as an indicator of the completeness of combustion.

Instrumentation for both O_2 and CO monitoring of boiler flue gas is commercially available, is considered to be reliable (Reference 12), and is already installed on many boilers as part of the excess air trim system. Both in-situ and extractive systems are being used. A variety of analyzers are used in these monitoring systems. These are reviewed in Reference 17 which also presents a list of vendors.

BOILER OPERATING CONDITIONS PROVIDING ACCEPTABLE DREs

Most of the testing that was undertaken during this program was accomplished at stable boiler operating conditions. In fact, test runs were suspended or aborted if the operation of a boiler became unstable during a test run. The data generated demonstrated conclusively that the DRE of hazardous compounds by boilers exceeds 99.99% under stable conditions. EPA recognized that boilers are not always operated at steady state and that the DRE might be less during unsteady state operations. For these reasons, special testing for the purpose of determining the effects of boiler operating conditions on the DRE of hazardous compounds were done at Site L. The objects of these tests were to determine whether DRE fell to dangerously low levels at unusual boiler operating conditions and to determine whether some relatively easily measured parameter would serve as an indicator of the DRE of hazardous compounds.

This section consists of two parts: a discussion of kinetic theory as it relates to DRE of hazardous compounds in boilers, and a discussion of the results that were were obtained during the unsteady state boiler operation tests. The discussion of the kinetic considerations was first presented in a previous EPA report (Reference 18). The second part is based on an incomplete analysis of the test data and interviews with the principal investigator and others who participated in the tests.

Kinetic Considerations

Currently available kinetic data suggest that thermal oxidation can be empirically described as a pseudo-first-order reaction:

$$\frac{dC}{dt} = -kC \qquad (1)$$

where: C = the concentration of the compound to be oxidized
k = the pseudo-first-order rate constant
t = time

Thus, the concentration of the compound at a given time, at constant temperature is:

$$\ln \left[\frac{C_t}{C_o}\right] = -kt \qquad (2)$$

where: C_o = the initial (t = 0) concentration

The rate constant can be expressed in Arrhenius form as:

$$k = A \exp[-E/RT] \qquad (3)$$

where: A = the apparent Arrhenius pre-exponential frequency factor
E = the apparent activation energy of reaction
R = the universal gas constant
T = absolute temperature

The pseudo-first-order rate constants for the thermal oxidation of several organic compounds have been measured using various adaptations of a thermal destruction analytical system (TDAS). The system consists of a narrow-bore quartz tube placed in a furnace capable of attaining, in some cases, temperatures up to 1,200°C. A gas supply (typically air) provides a continuous flow of gas through the unit. A test organic compound is introduced into the gas stream and carried into the apparatus where it is held at a constant high temperature for a set period of time (determined by the gas stream flow rate). As the vapor leaves the high-temperature quartz tube, reactions are quenched, and the product gas is carried to an analytical device such as a FID or a gas chromatograph/mass spectrometer (GC/MS). This analysis unit determines the final concentration (or fraction remaining) of the organic compound under investigation. Such information, developed as a function of temperature, can be used to determine the frequency factor and the apparent activation energy of the pseudo-first-order rate constant describing the compound's destruction.

Rate constant parameters determined in experiments using various forms of a TDAS could, ideally, be used to predict the degree of destruction effected by a combustion device. If the temperature-residence time environment presented by the combustor were known (and assuming destruction was kinetically controlled as described by the pseudo-first-order rate constant and not mixing, i.e., O_2 availability, controlled) DRE could be predicted by integrating Equation 1 over the temperature-residence time profile. Of course this is not possible since the details of the temperature-residence time profiles or practical combustors defy description.

However, one would expect that a relative ranking of incinerability could be established based on the magnitude of the pseudo-first-order rate constant at temperatures of incineration (or combustion) interest. That is, compounds with lower rate constants at incineration temperatures should be more thermally refractory than compounds with higher rate constants. Correspondingly, given rate constant data, it is possible to calculate from Equation 2 the temperature at which a certain degree of destruction (as measured by C/C_o) is attained for a given residence time at that temperature. For example, the temperature required to achieve 99.99% destruction ($C/C_o = 0.0001$) in 2 seconds could be calculated. Compounds predicted to require higher temperatures would be expected to be more thermally refractory than compounds requiring lower temperatures.

Table 4.22 shows just such rankings. For each compound for which rate constant data are available pseudo-first-order rate constant calculated at 2,850°F and the length of time required to attain 99.99% DRE at that temperature are shown. Species are ordered in Table 4.39 in decreasing order of difficulty of destruction. No obvious patterns that relate the predicted destructability to the percent chlorination, the presence of double bonds or heat of combustion are evident. It is interesting that methane is predicted to be more difficult to destroy than chloroform, chlorinated biphenyls, and some other compounds that one considers to be refractory. Chloroform is not ignitable; which means that the heat released during its combustion is insufficient to support its evaporation and molecular fractionation. This is apparently unrelated to the speed at which it fractures when exposed to an external heat source.

Also of note are the lengths of time that are predicted to be necessary to attain 99.99% destruction of these compounds. Even the longest are on the order of 1% of the average residence times of gas parcels in the flame zones of industrial boilers. The conclusion is that, even allowing for the imperfect predictions that often result from theory, the destruction of hazardous compounds by industrial boilers ought to be nearly quantitative if the flame configuration provides an adequate time/temperature contact. The mass-weighted DREs displayed in Table 4.15 confirm that, except in cases where the flame conditions were known to be poor, the DRE of hazardous compounds exceeded 99.999%. The destruction of methane, one of the compounds predicted to be relatively refractory, exceeded 99.999% at those sites where natural gas fuel was burned.

TABLE 4.39

FIRST ORDER REACTION RATE CONSTANT AND TIME NEEDED TO ATTAIN 99.99% DRE FOR SELECTED COMPOUNDS AT 2850°F[a]

Compound	First Order Reaction Rate Constant (k) at 2850°F	Time to Attain 99.99% DRE at 2850°F (seconds)
carbon tetrachloride	5.89×10^{2}	1.6×10^{-2}
hexachlorobenzene	3.23×10^{3}	2.9×10^{-3}
1,2,3,5 tetrachlorobenzene	6.43×10^{3}	1.4×10^{-3}
hexachloroethane	6.87×10^{3}	1.3×10^{-3}
chloromethane	1.01×10^{4}	9.1×10^{-4}
allyl chloride	1.35×10^{4}	6.8×10^{-4}
1,2 dichlorobenzene	3.03×10^{4}	3.0×10^{-4}
methane	1.08×10^{5}	8.5×10^{-5}
hexachlorobutadiene	6.11×10^{5}	1.5×10^{-5}
dichloromethane	7.09×10^{5}	1.3×10^{-5}
decachlorobiphenyl	1.02×10^{6}	9.0×10^{-6}
ethylene	1.26×10^{6}	7.3×10^{-6}
acrylonitrile	1.40×10^{6}	6.6×10^{-6}
acrolein	1.78×10^{6}	5.2×10^{-6}
1,2 dichloroethane	1.83×10^{6}	5.0×10^{-6}
toluene	4.39×10^{6}	2.1×10^{-6}
chloroform	4.69×10^{6}	2.0×10^{-6}
vinyl chloride	1.07×10^{7}	8.6×10^{-7}
1,2,4 trichlorobenzene	1.75×10^{7}	5.3×10^{-7}
ethane	1.81×10^{7}	5.1×10^{-7}
2,5,2',5' tetrachlorobiphenyl	4.79×10^{7}	1.9×10^{-7}
2,5,2',4',5' pentachlorobiphenyl	5.26×10^{7}	1.8×10^{-7}
chlorobenzene	1.05×10^{8}	8.5×10^{-8}
biphenyl	1.40×10^{8}	6.5×10^{-8}
propane	3.92×10^{9}	2.3×10^{-9}
benzene	2.97×10^{10}	3.1×10^{-10}

[a] Arrhenius factors and activation energies used to compute these data are from References 19, 20, and 21.

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SECTION 5

CHARACTERIZATION OF WASTE STREAMS

In this section, the waste streams generated and those which may be burned in boilers will be characterized. In the discussion below, sources of data on waste stream generation will be identified and evaluated. The estimates of the quantity of waste burned in industrial boilers will be profiled.

SOURCES OF DATA

Since the adoption of the Resource Conservation and Recovery Act (RCRA), the U.S. Environmental Protection Agency (EPA) has undertaken a variety of studies to quantify and characterize the amount of hazardous wastes generated in the U.S. Although some of these studies have been overlapping, the techniques used, the data sources, and the quality of the data differ from one study to the next. The major studies reviewed for this regulatory impact analysis (RIA) include the following:

- RCRA Risk-Cost Analysis Model (W-E-T Model)
- OSW Burner Questionnaire
- National Survey of Hazardous Waste Generators and Treatment, Storage, and Disposal Facilities Regulated Under RCRA in 1981 (Rainbow Survey)
- OSW Survey of the Synthetic Organic Chemical Industry
- MITRE Study of 104 Selected Waste Streams

Each of these data bases will be discussed in detail below. Because the RCRA Risk-Cost Analysis Model was considered to have the best data available for the purposes of this RIA, emphasis will be placed on it, and the other data bases will be evaluated in comparison to it. In the discussion of each data base, the data base will be described, its limitations identified, and the types of information included in the data base explained.

RCRA Risk-Cost Analysis Model

EPA developed the RCRA Risk-Cost Model or Waste-Environment-Technology (W-E-T) model to support the development of regulations authorized by RCRA. The model contains data on 154 waste streams, i.e., the combinations of substances, such as unusable byproducts or residues generated during a manufacturing process, that require disposal. Each waste stream is representative of the type of waste generated by any facility or plant of the various firms in a particular industry. The waste stream characteristics given in the data base are for a "typical" facility. Thus, simplifying assumptions were made about facility size and the uniformity of waste streams within a given industry. Data collection concentrated on the following industrial sectors identified by Standard Industrial Classification (SIC) code:

- SIC 25 - pulp and paper
- SIC 28 - chemical industry
- SIC 33 - primary metals
- SIC 29 - petroleum and coal products
- SIC 34 - fabricated metals

Since no primary data were collected, the waste profiles were developed from the following existing sources:

- State permit information
- RCRA Part B permit applications
- Trade associations
- CWA Development Documents
- Wastewater data from the Effluent Guidelines Division
- State studies on hazardous wastes

The data base also includes the following non-Subtitle C waste streams:

- Organic waste streams which contain more than one percent by weight of constituents of concern and have an annual generation greater than 100 metric tons. Although some of these waste streams have conventionally been considered to be within the jurisdiction of the Clean Water Act, their inclusion in the data base ensures flexibility in considering regulatory options by allowing the model to cross the boundary between hazardous and non-hazardous properties.

- A limited number of inorganic waste streams containing heavy metals not listed in 40 CFR 261 for the characteristic of EP toxicity.

- PCB wastes.

- Production wastes from quatenary amine (disinfectants) manufacture, distillation bottoms from linear alkyl benzene sulfonate (detergents) production, and off-specification commercial 2,4-dichlorophenoxyacetic acid, salts, and esters (a herbicide). These wastes pose a hazard based on potential ecological effects rather than effects on human health.

- High volume utility wastes including fly ash and flue gas desulfurization (FGD) sludge from conventional coal combustion.

The following wastes were specifically excluded from the data base:

- Hazardous wastes from federal and other government establishments

- Discarded products, off-specification products, and containers (RCRA class P and U wastes)

- Hazardous wastes from spills and abandoned sites

- State-designated hazardous wastes

- Mining wastes

- Asbestos separator wastes from diaphragm cell process chlorine production

Wastes from small generators have been partially included when a large volume of a particular waste stream with well-documented characteristics are generated by a large number of sources.

Although data gaps are frequent, the following types of information are available from this data base for each waste stream:

- Concentration of toxic constituents
- Portion of each constituent dissolved
- Quantity of waste produced per day, per facility
- Heat value
- Ash, chlorine, and non-water percentages
- Molecular weight, vapor pressure, solubility, and bio-degradation rate for each constituent
- Waste stream pH
- Fraction of waste stream suspended
- Amount of waste generated per year
- Number of facilities producing the waste
- Four-digit SIC codes of industries producing the waste
- Applicable treatment technologies

An EPA waste code associated with the waste stream is also included in the data base.

Because of the methods used to develop the data base, there are three major limitations in its use to characterize waste streams burned in industrial boilers. First, the "typical" waste streams included in the data base may not adequately represent all segments of the industry producing that waste because industrial processes can vary greatly within a given SIC. The data base does not contain any information on the variability of any of the waste characteristics. Second, not all burnable waste streams are characterized. Only those streams which are potentially toxic are included. Third, the data used to construct the waste profiles were often incomplete. If data for a particular stream were missing, constituent level estimates were based on analogies with other streams and on knowledge of the waste source.

OSW Burner Questionnaire

OSW recently undertook a three phase survey of burners of hazardous wastes. In the first phase, a comprehensive questionnaire was sent to 200 facilities believed to be burning waste as fuel. These 200 facilities were selected from a list compiled from anecdotal information and information contained in reports. Each facility surveyed was called, and answers to the questionnaire were taken over the telephone. Responses were obtained for only 100 facilities. In the second phase, EPA attempted to develop a list of all facilities in the U.S. burning waste as fuel. EPA's mailing list, which included 25,000 facilities was drawn from all industry types found in the U.S. but was weighted towards industries using large amounts of non-electric and non-natural gas energy sources and those SICs, e.g., the chemical industry, likely to burn waste as fuel. The third phase of this effort will be a sampling of those facilities with a positive response in the second phase using the questionnaire tested in the first phase.

Although the Burner Questionnaire includes a broad spectrum of information, the following types of information are most useful for profiling burnable wastes streams:

- Types of wastes burned by EPA waste code
- Description of the unit or process producing wastes which are burned
- Quantity of each waste burned
- Amount of waste burned as fuel which is generated off-site
- SIC code of off-site generator of wastes burned
- SIC code of facilities burning waste as fuel
- Specification limits such as minimum and maximum levels of Btu/lb, sulfur, halogen, ash, lead, and water content for devices burning waste as fuel

The following information was available from the second phase mailing:

- Number of facilities burning waste as fuel
- Number of facilities by SIC code burning waste as fuel
- Quantity of waste burned as fuel in 1982
- Quantity of waste burned during 1982 for each SIC code.

The results of the final Burner Questionnaire mailing as available, were used to update or modify earlier results. However, detailed information on constituents were not available for risk analyses based on actual wastes.

Data from the initial mailing was probably biased because no effort was made to ensure that the facilities sampled were representative of all facilities burning waste as fuel. Data from the second mailing was useful primarily for quantifying waste burned as fuel but not for profiling burnable waste streams. Data from the third mailing represents a comprehensive review of current practice.

Mail (Rainbow) Survey

Ten separate questionnaires were used to survey hazardous waste management practices. Of these questionnaires, the most useful for characterizing burnable waste streams were the Generator Questionnaire and the Treatment, Storage, and Disposal (TSD) General Questionnaire. A total of 11,220 Generator Questionnaires were mailed, and 9,877 responses were received. Of these, most (7,793) were excluded from the data base for the following reasons:

- The facility had filed a Part A application for protection but did not handle hazardous wastes.

- The facility was subject to a small quantity exemption under RCRA.

- The facility was subject to a farm exemption.

- 100 percent of the facility's hazardous waste was recycled, reclaimed, or reused.

Of the 2,348 responses to the TSD Questionnaire, 886 were excluded from the data base for the same reasons. Since burning waste for heat reclamation is considered a type of reuse, all facilities surveyed which burn all of their waste or otherwise recycle, reclaim, or reuse it were excluded. Data from these facilities were unavailable.

For the facilities included in the data base, the following type of information is available:

- Types of waste burned by EPA waste code
- Number of facilities burning each waste type
- Quantities of waste burned
- SIC codes of facilities burning waste as fuel
- Cross tabulation of any of the above information

Of course, this data base does not include information for many facilities from which responses were received.

Major limitations to the use of this data include the following:

- Certain groups of facilities which might be burning waste as fuel were excluded from the data base. Only those facilities which submitted either a Part A or notification form, which were not exempt under RCRA, and which burn waste as fuel would be included. Those generators that do not treat, store for more than 90 days, or dispose of hazardous waste on-site but do burn waste as fuel and, thus, are exempted under Part 261.6 of RCRA were not included.

- Extrapolations from data which have been highly cross-tabulated may not be statistically sound because extrapolation factors were based on the overall questionnaire rather than on the responses to a specific question.

- Exact quantity estimates of wastes burned as fuel cannot be obtained because of the wording of the waste-as-fuel question.

- No data on waste stream constituents or characteristics are available.

- As discussed above, a facility was excluded if it recycled, reclaimed, or reused (including burning) 100 percent of its hazardous wastes.

Thus, this data base was of limited usefulness to the RIA because of these limitations.

OSW Survey of the Synthetic Organic Chemical Industry

Because of the importance of the organic chemical manufacturing industry in the generation and management of hazardous wastes, OSW surveyed this industry. This data base includes the following types of information:

- Process information including block flow diagrams
- Constituent data
- Boiler operation data if the wastes are burned in boilers
- Btu, metals, and halogen contents of wastes burned as fuel

Information in the data base is treated by EPA as RCRA confidential because of industry claims.

The usefulness of this data base was limited by the following factors:

- Data aggregation to avoid compromising confidentiality greatly reduced the specificity of the information.
- EPA waste codes were not used. Thus, comparisons with other data bases were difficult.
- Constituent concentration data was only given by broad ranges. Significant over- or under-estimation of POHC burning rates was possible depending upon the assumptions used.
- The data base covered only one industry.

Because of these limitations, this data base was used solely to provide a general framework for estimating POHC burn rates. The maximum percentage in the range for a constituent and the average waste stream volume were used to estimate POHC quantities. These quantities were compared with estimates from other data bases.

MITRE Study of 104 Selected Waste Streams

A total of 104 waste streams were identified as both incinerable and potentially hazardous. Using OSW Background Documents and studies examining the waste management practices of relevant industries, each of these waste streams were characterized with the following information:

- Four-digit SIC number and EPA hazardous waste code
- Amount produced per year
- Heat content
- Listing of hazardous constituents
- Constituent levels for some of the waste streams
- Constituent level ranges for some of the waste streams

This data base was expanded later in the MITRE Incinerator Study which covered 413 hazardous waste streams incinerated at 204 facilities having operational hazardous waste incinerators.

Major limitations on the use of this data base include the following:

- Constituent data (concentrations or level ranges) are not given for each waste stream.

- Only 104 waste streams are characterized.

- Chlorine, ash, and water content data are usually not given.

However, this data base did provide a useful starting point for the identification of constituents.

QUANTITY OF HAZARDOUS WASTES GENERATED

Estimates of the quantity of hazardous wastes generated in the U.S. differ greatly. On April 27, 1984 EPA announced, as a result of a revision to the Rainbow survey, that 264 million metric tons of hazardous wastes regulated by RCRA were generated in 1981. Table 5.1 compares the waste quantity estimates in the RCRA Risk-Cost Analysis Model with other recent surveys.

Table 5.2 summarizes the quantities of waste managed in 1981 by waste group. The data in this table were taken from the results of the Rainbow survey because those data represent the most recent on the quantities of waste generated and managed in the U.S. Actually, the survey reported that only 71.3 billion gallons were managed in 1981. The data in the table reflects a higher total, i.e., 82.3 billion gallons for the following reasons:

- The respondents may have interpreted the term "handled" more broadly than intended in the survey by including wastes not managed on site, quantities carried over from previous years as stocks in hand, or wastes managed in RCRA exempt processes.

- Multiple hazardous waste codes were used to report some quantities. An estimated 6.6 billion gallons reported were mixtures of hazardous wastes. Solvents were sometimes reported as ignitable wastes. In both of the cases, the waste quantities were double-counted in Table 5.2.

CHARACTERIZATION OF WASTE STREAMS

Published data on hazardous waste stream characteristics are quite limited. One of the more extensive compilations of waste characteristics is from the W-E-T Model data base and is presented in Table 5.3. This data base and its limitations were described previously.

The metal content of a hazardous waste greatly influences the risk associated with its burning in an industrial boiler. For this reason, EPA reviewed the previously described data bases and solicited waste analyses results from hazardous waste burners to compile information on the metal content of hazardous waste. The following data were reviewed and analyzed to create Table 5.4 (References 1-11):

TABLE 5.1

COMPARISON OF SCOPE OF RCRA RISK-COST ANALYSIS MODEL DATA BASE WITH OTHER STUDIES[a]

Study	Waste Quantity (million metric tons/year)	Universe of Wastes	Data Sources
Risk-Cost Analysis Model (1984)	158	1. Potentially hazardous waste under Subtitle C, excluding: o Corrosive reactive and ignitable wastes o Discarded commercial chemical products 2. FGD sludge, fly ash, and wastes selected for ecosystem effects	EPA industry studies, permit applications, delisting petitions, state data, trade associations
OSW Mail Survey (1984)	160	Subtitle C hazardous wastes	Responses to Generator Questionnaire
	265		Responses to TSD General Questionnaire
PHB (1980)	41	Subtitle C hazardous wastes excluding commercial chemical products discarded	EPA industry studies
OTA (1983)	250	1. Subtitle C hazardous waste 2. State designated hazardous waste[b]	State data
Chemical Manufacturer Association (CMA) (1983)	9	Subtitle C hazardous wastes in SIC 28	Members survey for 1981

[a] Taken from The RCRA Risk-Cost Analysis Model: Phase III Report submitted to OSW by ICF, Inc., on January 13, 1984.

[b] Includes PCBs, waste oil, fly ash, oil field wastes, mining wastes, and other wastes for selected states.

TABLE 5.2

QUANTITIES OF HAZARDOUS WASTE HANDLED BY MANAGEMENT FACILITIES IN 1981 BY THE TYPE OF WASTE GROUP[a]

(Billions of Gallons)

Type of Waste	EPA Waste Codes Included in Category	Quantity Handled
Spent Halogenated and Nonhalogenated Solvents	F001-F005	3.2
Electroplating and Coating Wastewater Treatment Sludges and Cyanide-Bearing Bath Solutions and Sludges	F006-F019	2.6
Listed Industry Wastes from Specific Sources	K001-K106	13.0
Off-Specification or Discarded Commercial Chemical Products and Manufacturing Intermediates	U001-U247	2.9
Acutely Hazardous Wastes	P001-P123	0.2
Ignitable Wastes	D001	1.4
Corrosive Wastes	D002	33.0
Reactive Wastes	D003	3.2
E.P. Toxic Wastes	D004-D017	11.1
Unspecified (Including State Regulated and Self-Defined Hazardous Wastes)	----	11.7
TOTAL		82.3

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[a] Taken from National Survey of Hazardous Waste Generators and Treatment, Storage, and Disposal Facilities Regulated Under RCRA in 1981 submitted to OSW by Westat, Inc., in April 1984.

TABLE 5.3

RCRA RISK-COST MODEL
WASTE STREAMS BY SIC CODES

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
2491	N/A	01.01.07	25.10	120	0.0	0.0	0.0	0.900	0.1000E+00	ARSENIC	12000.00
										COPPER	7000.00
										CHROMIUM (VI)	15000.00
	K001	02.01.01	15.40	74	15000.0	0.0	0.05	0.900	0.9000E-01	PENTACHLOROPHENOL	780.00
	K001	02.04.01	35.70	171	12000.0	0.0	0.05	0.900	0.9000E-01	ACENAPHTHENE	300.00
										CHRYSENE	100.00
	TOTAL QUANTITY		76.20								
2812	N/A	01.01.01	25.90	6	0.0	0.0	0.0	0.750	0.5000E-01	LEAD	12500.00
	K106	01.01.03	7.00	26	0.0	0.0	0.0	0.500	0.3000E+00	MERCURY	21000.00
	K071	01.01.22	39.00	13	0.0	0.0	0.0	0.200	0.2000E+00	MERCURY	160.00
	K073	03.06.01	0.34	6	2600.0	0.85	0.02	0.0	0.2000E-01	CHLOROFORM	740000.00
										CARBON TETRACHLORIDE	110000.00
	TOTAL QUANTITY		72.24								
2816	N/A	01.01.05	742.10	8	0.0	0.0	0.0	0.520	0.4500E+00	CHROMIUM (VI)	9.00
	K002 K008	01.01.06	27.00	11	0.0	0.0	0.0	0.900	0.9000E-01	CHROMIUM (VI)	2160.00
										LEAD	760.00
	TOTAL QUANTITY		769.10								
2821	N/A	02.01.02	53.00	816	2000.0	0.0	0.20	0.750	0.2000E+00	PHENOL	50000.00
	N/A	02.01.03	486.00	816	2000.0	0.0	0.02	0.900	0.2000E-01	PHENOL	50000.00
										FORMALDEHYDE	20000.00
	TOTAL QUANTITY		539.00								
2823	N/A	01.01.20	160.00	24	0.0	0.0	0.0	0.950	0.4000E-01	ZINC	1750.00
	TOTAL QUANTITY		160.00								
2833	K084 K101 K102	01.05.01	0.50	3	0.0	0.0	0.0	0.700	0.2900E+00	ARSENIC	80000.00
	TOTAL QUANTITY		0.50								
285	F005	03.02.05	1.03	1500	34000.0	0.0	0.20	0.0	0.2000E+00	TOLUENE	200000.00
	TOTAL QUANTITY		1.03								
2851	N/A	01.05.02	0.50	1489	0.0	0.0	0.0	0.890	0.1000E+00	LEAD	11000.00
										MERCURY	15000.00
										THALLIUM	970.00
										DICHLOROMETHANE	120.00
	F005	03.01.09	5.43	1500	41600.0	0.0	0.10	0.100	0.1000E+00	TOLUENE	600000.00

TABLE 5.3--Continued

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
	F005	03.01.10	3.07	1500	33200.0	0.0	0.02	0.0	0.2000E-01	METHYL ETHYL KETONE	600000.00
	F005	03.02.06	0.58	1500	27100.0	0.0	0.20	0.0	0.2000E+00	METHYL ETHYL KETONE	200000.00
	TOTAL QUANTITY		9.58								
286	U240	03.06.04	43.50	8000	900.0	0.26	0.02	0.0	0.1000E+01	2,4-D	10000.00
	TOTAL QUANTITY		43.50								
2861	N/A	01.04.02	28.40	13	600.0	0.0	0.02	0.950	0.4800E-01	CHROMIUM (VI) ZINC	30.00 6700.00
	N/A	01.04.03	11.50	7	600.0	0.0	0.02	0.950	0.4800E-01	CHROMIUM (VI) COPPER NICKEL	26.00 380.00 290.00
	N/A	01.04.04	96.20	33	600.0	0.0	0.02	0.950	0.4800E-01	CHROMIUM (VI)	27.00
	TOTAL QUANTITY		136.10								
2865	K103	02.02.03	15.15	1	2900.0	0.0	0.02	0.929	0.0	NITROBENZENE BENZENE ANILINE	2000.00 500.00 68000.00
	K105	02.02.04	0.52	7	100.0	0.02	0.02	0.997	0.0	BENZENE CHLOROBENZENE 1,2-DICHLOROBENZENE 1,4-DICHLOROBENZENE	1800.00 80.00 500.00 500.00
	N/A	02.02.07	90.80	8	140.0	0.0	0.02	0.996	0.0	BENZENE MALEIC ANHYDRIDE	1780.00 1000.00
	N/A	02.02.09	30.00	11	1440.0	0.0	0.02	0.889	0.0	MALEIC ANHYDRIDE PHTHALIC ANHYDRIDE	100000.00 1000.00
	N/A	02.02.10	187.00	4	1300.0	0.0	0.02	0.965	0.0	ANILINE	35000.00
	N/A	02.02.15	388.00	12	800.0	0.0	0.02	0.920	0.0	PHENOL	20000.00
	N/A	02.02.17	136.20	5	1000.0	0.0	0.02	0.925	0.0	FORMALDEHYDE	14000.00
	N/A	02.02.18	118.00	5	650.0	0.0	0.02	0.977	0.0	PHENOL	13000.00
	N/A	02.02.20	12.50	12	300.0	0.0	0.02	0.700	0.0	PHENOL	10000.00
	K104	02.02.23	332.07	7	385.0	0.0	0.02	0.989	0.0	NITROBENZENE BENZENE ANILINE	1400.00 1200.00 7800.00
	K015	03.04.01	8.38	1	28000.0	0.44	0.10	0.0	0.2000E-01	1,2,4-TRICHLOROBENZE HEXACHLOROBENZENE TOLUENE BENZYL CHLORIDE	4000.00 4000.00 3000.00 5000.00
	K023	03.04.06	0.76	11	14000.0	0.0	0.10	0.0	0.2000E-01	PHTHALIC ANHYDRIDE MALEIC ANHYDRIDE	100000.00 900000.00
	K093	03.04.07	2.10	11	17000.0	0.0	0.02	0.0	0.2000E-01	PHTHALIC ANHYDRIDE MALEIC ANHYDRIDE	830000.00 170000.00
	K025	03.04.09	1.50	7	20900.0	0.0	0.02	0.0	0.2000E-01	M-DINITROBENZENE NITROBENZENE 4-NITROPHENOL 2,4-DINITROTOLUENE	311000.00 404000.00 31000.00 186000.00

TABLE 5.3--Continued

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
	K085	03.04.12	4.50	7	14000.0	0.56	0.10	0.0	0.5000E-01	HEXACHLOROBENZENE	100000.00
	K022	03.04.13	106.20	12	35000.0	0.0	0.05	0.0	0.1000E+00	BENZO(A)ANTHRACENE	1000.00
										BENZO(A)PYRENE	1000.00
										CHRYSENE	1000.00
										PHENOL	9000.00
	K083	03.04.15	1.80	9	36400.0	0.0	0.02	0.001	0.2000E-01	NITROBENZENE	22000.00
										BENZENE	58000.00
										ANILINE	907000.00
	N/A	03.04.18	5.60	7	33000.0	0.0	0.05	0.0	0.2000E-01	PHENOL	87000.00
	N/A	03.04.20	17.30	4	37000.0	0.11	0.02	0.0	0.2000E-01	CARBON TETRACHLORIDE	100000.00
										TOLUENE	500000.00
	N/A	03.04.21	22.70	53	41000.0	0.0	0.05	0.0	0.2000E-01	TOLUENE	100000.00
										BENZENE	100000.00
	K015	03.04.30	0.68	2	28000.0	0.45	0.10	0.0	0.2000E-01	BENZOTRICHLORIDE	90000.00
										1,2,4-TRICHLOROBENZE	6000.00
										HEXACHLOROBENZENE	6000.00
										TOLUENE	3000.00
										BENZYL CHLORIDE	13000.00
	K094	03.05.02	0.70	11	22100.0	0.0	0.10	0.0	0.1000E+01	PHTHALIC ANHYDRIDE	445000.00
	K027	03.05.05	107.90	8	25600.0	0.04	0.02	0.010	0.9000E+00	TOLUENE-2,4-DIAMINE	1.00
										TOLUENE-2,4-DIISOCYA	10.00
	K024	03.05.06	2.50	11	7000.0	0.0	0.10	0.0	0.1000E+01	PHTHALIC ANHYDRIDE	360000.00
										1,4-NAPHTHOQUINONE	360000.00
	TOTAL QUANTITY		1592.86								
2869	K009	02.02.01	399.50	3	395.0	0.01	0.02	0.970	0.0	CHLOROFORM	3000.00
										FORMALDEHYDE	3000.00
	K011 K013 K014	02.02.02	3181.00	6	2000.0	0.0	0.02	0.980	0.0	ACRYLONITRILE	400.00
										CYANIDE	3000.00
										ACETONITRILE	6000.00
	K026	02.02.05	1.44	1	20000.0	0.0	0.02	0.500	0.0	PARALDEHYDE	365000.00
										PYRIDINE	30000.00
	N/A	02.02.06	2.10	2	550.0	0.0	0.02	0.969	0.0	TOLUENE	500.00
	N/A	02.02.08	172.50	20	320.0	0.01	0.02	0.753	0.0	1,2-DICHLOROETHANE	8690.00
										VINYL CHLORIDE	2700.00
										METHYL CHLORIDE	2000.00
										CHLOROFORM	1000.00
										CARBON TETRACHLORIDE	785.00
	N/A	02.02.11	15.50	15	10000.0	0.0	0.02	0.645	0.2000E-01	ACETALDEHYDE	158000.00
										ETHYLENE OXIDE	197000.00
	N/A	02.02.12	8172.00	35	775.0	0.0	0.02	0.980	0.0	TOLUENE	2000.00
										PHENOL	4000.00
										BENZENE	8000.00
	N/A	02.02.13	5448.00	35	800.0	0.0	0.02	0.980	0.0	TOLUENE	4000.00
										PHENOL	3000.00
										BENZENE	5000.00

TABLE 5.3--Continued

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
	N/A	02.02.14	1398.30	4	536.0	0.0	0.02	0.300	0.0	METHYL METHACRYLATE	300.00
	N/A	02.02.16	291.50	15	400.0	0.0	0.02	0.990	0.0	ETHYLENE OXIDE	10000.00
	N/A	02.02.19	45.40	10	0.0	0.01	0.02	0.888	0.0	CARBON TETRACHLORIDE	13000.00
	N/A	02.02.21	3.63	6	1000.0	0.16	0.02	0.710	0.0	METHYL ETHYL KETONE	3000.00
	N/A	02.02.22	2.72	1	700.0	0.30	0.02	0.640	0.0	METHYL ETHYL KETONE	20000.00
	N/A	03.03.02	2.60	1	2700.0	0.0	0.02	0.0	0.1000E+00	COPPER	3000.00
										NICKEL	6000.00
										HYDROQUINONE	260000.00
	K017	03.04.02	6.36	3	8700.0	0.81	0.10	0.0	0.5000E-01	EPICHLOROHYDRIN	20000.00
										1,2-DICHLOROPROPANE	100000.00
										BIS(CHLOROMETHYL)ETH	140000.00
	K018	03.04.03	35.40	5	6400.0	0.78	0.02	0.0	0.5000E-01	1,2-DICHLOROETHANE	110000.00
										HEXACHLOROBENZENE	215000.00
										HEXACHLOROBUTADIENE	215000.00
										TRICHLOROETHENE	320000.00
	K019	03.04.04	80.30	17	9300.0	0.56	0.05	0.0	0.2000E-01	1,2-DICHLOROETHANE	206000.00
										1,1,1-TRICHLOROETHAN	242000.00
										1,1,1,2-TETRACHLOROE	121000.00
										1,1,2,2-TETRACHLOROE	121000.00
	K020	03.04.05	52.70	15	9300.0	0.71	0.05	0.0	0.2000E-01	VINYL CHLORIDE	2000.00
										1,1,1,2-TETRACHLOROE	211000.00
										1,1,2-TRICHLOROETHAN	272000.00
										1,2-DICHLOROETHANE	242000.00
	N/A	03.04.08	5.80	1	25200.0	0.0	0.10	0.0	0.2000E-01	CYCLOHEXANE	200000.00
	N/A	03.04.10	0.96	9	4700.0	0.91	0.02	0.0	0.2000E-01	CARBON TETRACHLORIDE	926000.00
										TRICHLOROETHENE	74000.00
	K030	03.04.11	48.40	10	9300.0	0.77	0.10	0.0	0.5000E-01	HEXACHLOROBENZENE	200000.00
										HEXACHLOROBUTADIENE	338000.00
										1,1,2,2-TETRACHLOROE	230000.00
										1,1,1,2-TETRACHLOROE	63000.02
	K010	03.04.14	26.30	3	7700.0	0.17	0.02	0.470	0.2000E-01	ACETALDEHYDE	162000.00
										CHLOROACETALDEHYDE	119000.00
										CHLOROFORM	20000.00
										FORMALDEHYDE	20000.00
	K029	03.04.16	1.30	3	11600.0	0.78	0.02	0.0	0.2000E-01	1,2-DICHLOROETHANE	170000.00
										1,1,1-TRICHLOROETHAN	830000.00
	N/A	03.04.17	3.60	8	7000.0	0.0	0.05	0.0	0.2000E-01	MALEIC ANHYDRIDE	123000.00
	N/A	03.04.19	2.70	7	44000.0	0.0	0.02	0.0	0.2000E-01	BENZENE	451000.00
										CYCLOHEXANE	451000.00
	N/A	03.04.22	101.70	11	22100.0	0.0	0.05	0.001	0.2000E-01	METHYL ETHYL KETONE	9300.00
	N/A	03.04.23	8.20	3	28000.0	0.34	0.05	0.0	0.2000E-01	1,3-DICHLOROPROPENE	510000.00
	N/A	03.04.24	22.70	4	34000.0	0.0	0.02	0.050	0.2000E-01	METHYL ETHYL KETONE	90000.00
	N/A	03.04.25	1.40	1	2700.0	0.0	0.02	0.005	0.2000E-01	ACETALDEHYDE	857000.00
										HYDROQUINONE	14000.00
										ACROLEIN	119000.00
	N/A	03.04.26	4.50	1	15100.0	0.0	0.02	0.360	0.2000E-01	FORMALDEHYDE	20000.00

TABLE 5.3--Continued

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
	N/A	03.04.27	1.40	2	15500.0	0.02	0.05	0.400	0.2000E-01	ACROLEIN	240000.00
										1,1-DICHLOROETHENE	24000.00
	N/A	03.04.28	0.82	2	23000.0	0.02	0.05	0.060	0.2000E-01	2-CHLOROPHENOL	80000.00
	N/A	03.04.29	1.60	1	13000.0	0.0	0.20	0.001	0.2000E-01	ACROLEIN	1000.00
										METHYL ETHYL KETONE	1000.00
										ALLYL ALCOHOL	30000.00
	N/A	03.04.31	0.04	20	34000.0	0.03	0.02	0.0	0.1000E-01	BENZYL CHLORIDE	10000.00
										DIMETHYL ALKYLAMINE	50000.00
										BENZALKONIUM CHLORID	100000.00
	N/A	03.04.32	190.60	3	17000.0	0.03	0.05	0.0	0.0	TCDD	170.00
	K016	03.05.01	1.60	10	4700.0	0.87	0.10	0.0	0.1000E+01	HEXACHLOROBENZENE	40000.00
										HEXACHLOROBUTADIENE	40000.00
										HEXACHLOROETHANE	200000.00
										TETRACHLOROETHENE	200000.00
	K095	03.05.03	35.50	4	6300.0	0.83	0.10	0.0	0.1000E+01	1,1,1,2-TETRACHLOROE	240000.00
										1,1,2,2-TETRACHLOROE	270000.00
	K096	03.05.04	3.20	1	5800.0	0.77	0.10	0.0	0.1000E+01	1,2-DICHLOROETHANE	167000.00
										1,1,1-TRICHLOROETHAN	271000.00
										1,1,2-TRICHLOROETHAN	271000.00
										1,1,1,2-TETRACHLOROE	70000.00
										1,1,2,2-TETRACHLOROE	70000.00
										HEXACHLOROETHANE	140000.00
	N/A	03.05.07	9.10	2	6400.0	0.24	0.50	0.0	0.1000E+01	1,3-DICHLOROPROPAN-1	270000.00
	N/A	03.05.08	43.65	48	27000.0	0.0	0.02	0.0	0.1000E+01	NAPHTHALENE	40000.00
										ACENAPHTHENE	40000.00
										LAS	100000.00
	K021	05.02.01	0.27	2	0.0	0.0	0.0	0.0	0.9990E+00	ANTIMONY	999000.00
										CARBON TETRACHLORIDE	1000.00
	K028	05.02.02	0.61	4	6000.0	0.83	0.20	0.0	0.1000E+01	1,1,1-TRICHLOROETHAN	10000.00
										VINYL CHLORIDE	10000.00
	TOTAL QUANTITY		19826.84								
2879	K041 K098	02.03.61	5.00	2	10000.0	0.0	0.20	0.750	0.2200E+00	TOXAPHENE	10000.00
	N/A	02.03.90	500.00	439	35000.0	0.0	0.20	0.750	0.2200E+00	PARATHION	30000.00
	N/A	02.03.91	500.00	439	30000.0	0.0	0.20	0.750	0.2000E+00	CHLORDANE	30000.00
	F002	03.01.07	1.23	353	31850.0	0.16	0.02	0.0	0.2000E-01	CHLOROBENZENE	500000.00
	TOTAL QUANTITY		1006.23								
2892	N/A	01.02.03	24000.00	48	0.0	0.0	0.0	0.985	0.1000E-02	LEAD	180.00
	K044 K046	01.05.04	1.70	29	400.0	0.0	0.05	0.940	0.5000E-01	LEAD	5000.00
	TOTAL QUANTITY		24001.70								
2893	K086	01.05.03	10.00	453	0.0	0.0	0.05	0.930	0.6000E-01	CHROMIUM (VI)	150.00
										LEAD	760.00
										TOLUENE	100.00
	TOTAL QUANTITY		10.00								

TABLE 5.3--Continued

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
2911	N/A	01.01.04	20.60	225	200.0	0.0	0.20	0.750	0.2400E+00	CHROMIUM (VI)	13.00
										LEAD	9.00
	N/A	01.04.01	263.90	140	3000.0	0.0	0.10	0.850	0.1000E+00	CHROMIUM (VI)	4.00
										LEAD	1.00
	K048	04.01.01	297.60	160	5300.0	0.0	0.10	0.790	0.1000E+00	CHROMIUM (VI)	8.00
										LEAD	1.00
	K049	04.01.02	92.40	171	20000.0	0.0	0.20	0.380	0.2700E+00	CHROMIUM (VI)	6.00
										LEAD	3.00
	K050	04.01.03	1.70	106	2000.0	0.0	0.30	0.610	0.3400E+00	CHROMIUM (VI)	10.00
										LEAD	28.00
	K051	04.01.04	196.20	205	8000.0	0.0	0.20	0.630	0.1800E+00	CHROMIUM (VI)	4.00
										LEAD	75.00
	K052	04.01.05	7.10	185	3500.0	0.0	0.50	0.420	0.5000E+00	CHROMIUM (VI)	1.00
										LEAD	630.00
	N/A	04.01.06	154.70	140	11000.0	0.0	0.50	0.340	0.4400E+00	CHROMIUM (VI)	2.00
										LEAD	4.00
	N/A	04.01.07	1.00	153	15000.0	0.0	0.20	0.430	0.2300E+00	CHROMIUM (VI)	1.00
										LEAD	3.00
	N/A	04.01.08	40.30	140	2000.0	0.0	0.50	0.430	0.5200E+00	CHROMIUM (VI)	25.00
										LEAD	53.00
	TOTAL QUANTITY		1075.50								
2992	N/A	04.02.01	69.00	6	7000.0	0.0	0.70	0.0	0.7000E+00	LEAD	40000.00
										BENZO(A)ANTHRACENE	10000.00
										BENZO(A)PYRENE	10000.00
	N/A	04.02.02	32.00	6	20000.0	0.0	0.20	0.100	0.1000E+00	LEAD	10000.00
										BENZO(A)ANTHRACENE	10000.00
										BENZO(A)PYRENE	10000.00
	N/A	04.02.03	9.00	2	21000.0	0.0	0.20	0.600	0.1000E+00	LEAD	20000.00
										BENZO(A)ANTHRACENE	40000.00
										BENZO(A)PYRENE	10000.00
	TOTAL QUANTITY		110.00								
3000	N/A	05.03.02	52.00	196	0.0	0.0	0.0	0.0	0.1000E+01	BARIUM	1000.00
										LEAD	100.00
										NICKEL	100.00
										VANADIUM	150.00
										ZINC	10000.00
										CHROMIUM (VI)	150.00
	TOTAL QUANTITY		52.00								
3312	N/A	01.01.12	30.00	10	0.0	0.0	0.0	0.900	0.5000E-01	CHROMIUM (VI)	28.00
										LEAD	69.00

TABLE 5.3--Continued

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
	N/A	01.01.13	60.00	63	0.0	0.0	0.0	0.914	0.3000E-01	CHROMIUM (VI)	300.00
	K061	01.01.21	70.00	16	0.0	0.0	0.0	0.800	0.1500E+00	CADMIUM	200.00
										CHROMIUM (VI)	1000.00
										LEAD	2920.00
	K062	01.02.01	2950.00	689	0.0	0.0	0.0	0.800	0.2000E-02	CHROMIUM (VI)	10.00
										LEAD	100.00
	K060	01.03.01	72.00	62	0.0	0.0	0.0	0.950	0.4000E-01	CYANIDE	7400.00
										PHENOL	1000.00
										ARSENIC	1100.00
	K087	03.06.02	39.80	36	33000.0	0.0	0.20	0.0	0.9700E+00	NAPHTHALENE	150000.00
										PHENOL	1700.00
	K061	05.01.01	463.60	70	0.0	0.0	0.0	0.0	0.1000E+01	CADMIUM	1000.00
										CHROMIUM (VI)	500.00
										LEAD	15000.00
	TOTAL QUANTITY		3685.40								
3313	N/A	01.01.17	32.80	5	0.0	0.0	0.0	0.750	0.2000E+00	NICKEL	1000.00
										CHROMIUM (VI)	50.00
	N/A	05.01.02	83.60	12	0.0	0.0	0.0	0.0	0.1000E+01	LEAD	600.00
	N/A	05.01.03	72.20	13	0.0	0.0	0.0	0.0	0.1000E+01	LEAD	2300.00
	N/A	05.01.04	85.40	15	0.0	0.0	0.0	0.0	0.1000E+01	CHROMIUM (VI)	3600.00
										LEAD	650.00
	TOTAL QUANTITY		274.00								
3320	N/A	05.01.05	2139.10	2000	0.0	0.0	0.0	0.0	0.1000E+01	CADMIUM	180.00
										LEAD	10000.00
	N/A	05.01.06	16915.10	2000	0.0	0.0	0.0	0.0	0.1000E+01	CADMIUM	60.00
	TOTAL QUANTITY		19054.20								
3331	N/A	01.01.14	640.00	17	0.0	0.0	0.0	0.800	0.1500E+00	CADMIUM	520.00
										LEAD	8000.00
	TOTAL QUANTITY		640.00								
3332	N/A	01.01.08	42.00	4	0.0	0.0	0.0	0.800	0.1800E+00	CADMIUM	134.00
										LEAD	25500.00
	TOTAL QUANTITY		42.00								
3333	N/A	01.01.09	11.00	7	0.0	0.0	0.0	0.800	0.1800E+00	CADMIUM	66000.00
										LEAD	4200.00
	N/A	01.01.10	16.00	5	0.0	0.0	0.0	0.800	0.1800E+00	CADMIUM	141.00
										LEAD	26000.00

TABLE 5.3--Continued

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
	N/A	01.01.15	0.50	5	0.0	0.0	0.0	0.500	0.4900E+00	CADMIUM	140.00
										LEAD	107500.00
	TOTAL QUANTITY		27.50								
3341	K069	01.01.18	28.60	3	0.0	0.0	0.0	0.750	0.2000E+00	CADMIUM	85.00
										CHROMIUM (VI)	7.00
										LEAD	13000.00
	K069	05.01.07	10.00	73	0.0	0.0	0.0	0.0	0.1000E+01	CADMIUM	900.00
										CHROMIUM (VI)	150.00
										LEAD	120000.00
	N/A	05.01.08	153.30	30	0.0	0.0	0.0	0.0	0.1000E+01	COPPER	12000.00
										ZINC	40000.00
										LEAD	2800.00
	TOTAL QUANTITY		191.90								
3351	N/A	01.01.19	8.00	20	0.0	0.0	0.0	0.900	0.5000E-01	COPPER	30000.00
	TOTAL QUANTITY		8.00								
3398	F010 F011	01.03.02	6.00	95	2300.0	0.0	0.15	0.800	0.1000E+00	CYANIDE	50000.00
	TOTAL QUANTITY		6.00								
3471	F006 F008	01.01.16	488.40	4522	0.0	0.0	0.0	0.940	0.5000E-01	COPPER	1800.00
										CHROMIUM (VI)	680.00
										CADMIUM	350.00
										LEAD	400.00
										NICKEL	3650.00
	F007 F009	01.02.02	1990.00	4522	0.0	0.0	0.0	0.995	0.2000E-02	CADMIUM	100.00
										COPPER	140.00
										CYANIDE	75.00
										CHROMIUM (VI)	170.00
										NICKEL	1500.00
	N/A	01.02.04	30.70	3090	0.0	0.0	0.0	0.990	0.2000E-02	COPPER	24.00
										CYANIDE	6.00
										FLUORINE (FLUORIDES)	9.00
										NICKEL	23.00
	N/A	01.02.05	17300.00	4522	0.0	0.0	0.0	0.999	0.0	COPPER	6.00
										CYANIDE	50.00
										CHROMIUM (VI)	17.00
										NICKEL	2.00
										ZINC	3.00
	TOTAL QUANTITY		19809.10								

TABLE 5.3--Continued

SIC CODE	EPA NUMBER(S)	WASTE STREAM NUMBER	QUANTITY (1000 MT/YR)	NO OF FAC	HEATING VALUE (KJ/KG)	FRACT CL	FRACT ASH	FRACT WATER	FRACTION SUSPENDED	CONSTITUENT	CONCENTRATION (PPM)
3691	N/A	01.01.11	150.00	202	0.0	0.0	0.0	0.890	0.1000E+00	LEAD	35000.00
	TOTAL QUANTITY		150.00								
3692	N/A	05.03.01	1.30	41	0.0	0.0	0.0	0.0	0.1000E+01	CADMIUM	10000.00
										LEAD	10000.00
										MERCURY	10000.00
	TOTAL QUANTITY		1.30								
721	1002	03.02.01	38.04	18000	17100.0	0.51	0.20	0.0	0.2000E+00	TETRACHLOROETHENE	600000.00
	1002	03.02.04	9.51	18000	8200.0	0.21	0.60	0.0	0.1000E+01	TETRACHLOROETHENE	250000.00
	TOTAL QUANTITY		47.55								
N/A	N/A	01.01.02	24400.00	70	0.0	0.0	0.0	0.500	0.4500E+00	ARSENIC	18.00
										BARIUM	260.00
										CADMIUM	13.00
										LEAD	145.00
	1001	03.01.01	25.53	111712	13200.0	0.49	0.10	0.100	0.1000E+00	TRICHLOROETHENE	600000.00
	1001	03.01.02	45.24	176808	13200.0	0.48	0.10	0.100	0.1000E+00	1,1,1-TRICHLOROETHAN	600000.00
	1001	03.01.03	10.14	21479	12100.0	0.50	0.10	0.100	0.1000E+00	DICHLOROMETHANE	600000.00
	1001	03.01.04	19.83	48784	12600.0	0.51	0.10	0.100	0.1000E+00	TETRACHLOROETHENE	600000.00
	1002	03.01.05	7.68	3219	6800.0	0.48	0.02	0.0	0.2000E-01	1,1,1-TRICHLOROETHAN	800000.00
	1002	03.01.06	20.68	23294	5100.0	0.67	0.02	0.0	0.2000E-01	DICHLOROMETHANE	800000.00
	1004	03.01.08	0.48	1000	24700.0	0.0	0.02	0.0	0.2000E-01	NITROBENZENE	500000.00
	1002	03.02.02	2.56	41580	5600.0	0.16	0.20	0.0	0.2000E+00	1,1,1-TRICHLOROETHAN	200000.00
	1002	03.02.03	9.19	4158	4200.0	0.17	0.20	0.0	0.2000E+00	DICHLOROMETHANE	200000.00
	N/A	03.03.01	29.00	72220	25300.0	0.0	0.20	0.250	0.2000E+00	TOLUENE	10000.00
										METHYL ETHYL KETONE	10000.00
										CHROMIUM (VI)	56.00
										LEAD	40.00
										MERCURY	12.00
	N/A	03.03.90	73.00	396	4000.0	0.0	0.20	0.600	0.2000E+00	CHROMIUM (VI)	1000.00
										TOLUENE	10000.00
	N/A	03.06.03	4.50	6163	23000.0	0.56	0.02	0.0	0.0	PCB-1254	500000.00
										1,2,4-TRICHLOROBENZE	500000.00
	N/A	05.03.03	40240.00	80480	0.0	0.0	0.0	0.0	0.1000E+01	ARSENIC	40.00
										BARIUM	1000.00
										CHROMIUM (VI)	140.00
										LEAD	90.00
	TOTAL QUANTITY		64887.81								

TABLE 5.4

METAL LEVELS IN HAZARDOUS WASTE FUELS IN PPM (References 1-11)

	Ash	As	Ba	Cd	Cr	Pb	Ni	Hg
No. of Samples	40	186[a]	159[a]	191[a]	198	199	169	175
90th Percentile	20	18[a]	251[a]	10[a]	296	572	25	<1
50th Percentile	2.82	.5	<5	<.5	<5	<8	<2	<.06
10th Percentile	.05	.02	<.2	<.1	<.2	<.5	<.2	<.01

Note: "Less than" values were included at the detection limit when determining means and percentiles. Where "less than" values contribute significantly to the sum of all values, the means and percentiles are presented as "less than" values.

[a] Some used oil data was included in the data base for 90% worst As, Ba, and Cd.

- Thirty samples from Reference 1 (those wastes with heating values greater than 5,000 Btu/lb).

- Six samples from kiln test burn reports, Sites B-G (References 2-7).

- Twenty-two data points presented in the Mitre reports for spent flammable solvents and chlorinated solvents (References 8-9). Given that a low/high range was presented for metals levels in many waste streams, such wastes were included in the data base as two wastes, one with the low metals level and one with the high metals level; thus, the 22 data points were derived from 13 waste streams as characterized by Mitre.

- One hundred forty-two samples from a company participating in the Keystone workshop (Reference 10), burning 100% waste in lightweight aggregate kilns.

- Five samples from ICF (W-E-T Model) data base of wastes as generated (Reference 11).

- Other waste streams characterized for metals by Mitre and ICF (W-E-T Model) either had low heating value (less than 5,000 Btu/lb) and are not currently burned as fuels, or were waste streams known not to be burned as fuels (e.g., petroleum refinery wastes typically sent to petroleum cokers or land treatment).

Some data on arsenic, barium, and cadmium levels in waste oil were included in the data base used to compute the 90th percentile values.

QUANTITY OF HAZARDOUS WASTE BURNED IN INDUSTRIAL BOILERS

Basic data for quantifying the amount of hazardous waste burned in industrial boilers were available from the OSW Burner Questionnaire. The limitations of this data base which were discussed above must be remembered. Table 5.5 shows the breakdown of hazardous wastes as to the amount burned versus the total generated. Table 5.6 provides estimates of distribution waste burned by SIC code. These data represent the latest and best estimate of the quantity of hazardous waste being burned.

TABLE 5.5

BURNABLE HAZARDOUS WASTE UNIVERSE

Item	Waste Quantity (million metric tons per year)
Total Hazardous Waste Generated	160
Total Burnable Hazardous Waste	25
Amount Burned:	
Incinerators	2
Boilers <50 Million Btu/hr	<1
Boilers 50-100 Million Btu/hr	1
Boilers >100 Million Btu/hr	2
Kilns, Etc.	0.35
Total	6

TABLE 5.6

ESTIMATES OF WASTE-DERIVED FUEL BY SIC[a]

SIC Code	Industry	Quantity (million gal/yr)	Number of Facilities
20	Food Products	3.4	104
22	Textile Mill Production	0.2	135
24	Lumber and Wood	100.9	273
25	Furniture and Fixtures	113.1	118
26	Paper and Allied Production	213.9	117
27	Printing and Publishing	173.2	118
28	Chemical and Allied	375.8	320
29	Petroleum and Related	84.9	78
30	Rubber and Plastics	30.9	76
31	Leather and Leather Production	0.03	2
32	Stone, Clay, Glass, Concrete	9.0	26
33	Primary Metals	73.4	145
34	Fabricated Metals	1.1	47
35	Non-Electric Machinery	0.4	162
36	Electrical Equipment	0.01	13
37	Transportation Equipment	0.6	131
39	Miscellaneous Manufacturing	0.2	27
40	Railroad Transportation	0.004	7
42	Motor Freight Transport	0.02	14
49	Electric, Gas, Sanitation Serv.	0.07	43
51	Wholesale Trade-Nondur.	0.1	7
72	Personal Services	0.3	477
75	Auto Repair and Services	0.03	198
TOTAL		1009.4	2639

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[a] Data from EPA's Burner Questionnaire.

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10. Burning of Hazardous Waste in Industrial Boilers and Furnaces. A Keystone Center Workshop. Washington, D.C. February 11, 1986.

11. RCRA Risk - Cost Analysis Model Waste Stream Data Base. SCS Engineers. July 1984.

SECTION 6

COST ELEMENTS FOR REGULATORY ANALYSIS

A key element of the RIA is an assessment of the potential economic impact of the various regulatory options being considered. This section identifies the major cost factors being considered in the assessment and provides the cost data that are not being obtained from other sources.

Regulating the burning of hazardous waste in industrial boilers could potentially have an economic impact on those being regulated as well as the regulatory agencies. This section is limited to the costs associated with burning the wastes. Potential cost to regulatory agencies are addressed in a separate document (Reference 1).

The economic impact on those burning hazardous waste in industrial boilers is being analyzed by EPA in terms of how the net fuel and waste disposal savings is altered by the various regulatory options. This net savings is the difference in: (1) the credits associated with the fuel replacement and the elimination of alternative waste disposal waste; and (2) the increased capital and operating costs associated with firing waste above that for firing conventional fuels. Therefore, to analyze the economic impact of a regulatory option, cost data for the significant elements of these credits and incremental costs are needed. The choice of cost elements will depend, to a large extent, on the level of detail specified in the analysis. These data are being obtained from a number of sources. The items being provided in this document fall into three major categories: (1) conventional fuel prices, (2) costs to modify the boiler system to fire the waste, and (3) the major operating and maintenance costs associated with burning wastes.

CONVENTIONAL FUEL PRICES

The prices of conventional fuels used by industrial boilers are used in the analysis of fuel replacement credits. Two sets of prices are presented here. The first set is for 1982, which is the year covered by the OSW Burner Questionnaire survey of waste fuel users. The results of this survey are also being used in the economic impact anlaysis. Having the fuel prices index for the period covered by the survey facilitates the economic impact analysis. The 1982 prices are:

- Natural gas - \$3.63 per million Btu
- Distillate Oil - \$7.24 per million Btu
- Residual Oil - \$4.62 per million Btu
- Coal - \$1.09 per million Btu

The above prices were developed from data taken from publications by the Energy Information Administraiton which is the branch of the Department of Energy responsible for collecting, compiling, and disseminating data on U.S. energy cost and usage. Natural gas and oil prices were developed from data provided in Reference 2 while coal prices are based on data from Reference 3. These prices are representative of the national average values paid by industrial users in 1982.

One aspect of the RIA is to estimate the impact of the regulation on future operations of the waste burner. Projected fuel prices for the period covered by the analysis are therefore needed. Projected fuel prices have already been generated for use in developing New Source Performance Standards (NSPS) for industrial boilers. Fuel prices projected for the period 1985 through 2010, are listed in Tables 6.1 through 6.4. These projections were taken from Reference 4 and are currently being used by the EPA Office of Air Quality Planning and Standards (OAQPS) Branch for its economic modeling. Updates to these costs are made periodically. Mr. Robert Short is the EPA Project Engineer responsible for the updates. He is located at Research Triangle Park, North Carolina.

BOILER SYSTEM MODIFICATION COSTS

When fossil fuel-fired boilers are used to burn hazardous wastes, capital expenditures may be required for a number of system modifications, including: waste pretreatment, storage and handling facilities; boiler modifications; and combustion control instrumentation modification. Additional expenditures may be incurred as a result of regulatory requirements. For instance, restrictions on emissions of particulate matter, metals, and hydrochloric acid may require additional air control equipment or modifications to existing devices. Further capital outlays will result if waste feed metering and monitoring of the boiler temperature, combustion gas O_2 and CO levels are required.

Cost data for the above elements have been aggregated into three groups:

- Waste pretreatment costs
- Boiler modifications costs
- Air pollution control device costs

The cost data presented below were developed from published data, vendor information and engineering judgement. The following discusses the various elements comprising these three groups with one exception. Cost data for waste storage and handling facilities have been generated by the EPA for its economic modeling efforts and are not presented here. However, these data, which are documented in Reference 5, are being used in impact analysis.

TABLE 6.1

PROJECTIONS OF REGIONAL INDUSTRIAL NATURAL GAS PRICES[a]
(1982 $ per million Btu)

	Demand Region	1985	1990	1995	2000	2005	2010
1.	New England	6.09	7.16	8.50	11.47	14.67	16.50
2.	New York/New Jersey	4.90	5.41	6.42	8.67	11.09	12.47
3.	Middle Atlantic	4.29	4.59	5.45	7.35	9.40	10.57
4.	South Atlantic	4.82	5.70	6.76	9.13	11.67	13.13
5.	Midwest	4.14	4.90	5.81	7.85	10.03	11.29
6.	Southwest	4.27	4.63	5.50	7.42	9.49	10.67
7.	Central	3.77	4.55	5.40	7.30	9.33	10.49
8.	North Central	4.22	4.79	5.68	7.67	9.81	11.04
9.	West	4.69	5.44	6.45	8.71	11.14	12.53
10.	Northwest	4.90	5.08	6.03	8.15	10.41	11.72

[a] Taken from Reference 4.

TABLE 6.2

PROJECTIONS OF REGIONAL INDUSTRIAL RESIDUAL FUEL OIL PRICES[a,b]

(1982 $ per million Btu)

	Demand Region	1985	1990	1995	2000	2005	2010
1.	New England	4.09	5.15	7.32	8.92	11.11	12.78
2.	New York/New Jersey	4.02	5.09	7.23	8.82	10.98	12.63
3.	Middle Atlantic	4.01	5.09	7.22	8.81	10.97	12.62
4.	South Atlantic	4.20	5.32	7.56	9.21	11.48	13.20
5.	Midwest	4.34	5.44	7.73	9.42	11.73	13.50
6.	Southwest	4.43	5.63	8.00	9.75	12.14	13.97
7.	Central	4.40	5.51	7.83	9.54	11.89	13.67
8.	North Central	4.25	5.40	7.67	9.35	11.65	13.40
9.	West	4.49	5.71	8.10	9.88	12.31	14.16
10.	Northwest	4.31	5.49	7.79	9.50	11.84	13.62

[a] 1.6% sulfur.
0.3% sulfur = 1.6% sulfur + $0.68/MMBtu.
0.8% sulfur = 1.6% sulfur + $0.35/MMBtu.
3.0% sulfur = 1.6% sulfur - $0.45/MMBtu.

[b] Taken from Reference 4.

TABLE 6.3

PROJECTIONS OF REGIONAL INDUSTRIAL DISTILLATE FUEL OIL PRICES[a]
(1982 $ per million Btu)

	Demand Region	1985	1990	1995	2000	2005	2010
1.	New England	6.33	7.28	10.02	12.07	14.84	16.96
2.	New York/New Jersey	6.27	7.22	9.93	11.97	14.71	16.82
3.	Middle Atlantic	6.24	7.18	9.88	11.90	14.63	16.72
4.	South Atlantic	6.08	7.03	9.68	11.66	14.34	16.39
5.	Midwest	6.20	7.13	9.82	11.83	14.54	16.62
6.	Southwest	6.08	7.06	9.72	11.71	14.40	16.45
7.	Central	6.15	7.08	9.74	11.73	14.42	16.49
8.	North Central	5.98	6.94	9.55	11.50	14.14	16.16
9.	West	6.04	7.01	9.65	11.63	14.29	16.34
10.	Northwest	6.04	7.01	9.65	11.63	14.29	16.34

[a] Taken from Reference 4.

TABLE 6.4

DELIVERED INDUSTRIAL COAL PRICE FORECAST[a,b]
(January 1983 $ per million Btu)

Demand Region	Coal Type	Sulfur Content (lb SO_2/MMBtu)	1985	1990	1995	2000
1. New England	Bituminous	<0.80	3.53	3.77	3.93	4.01
		0.80 - 1.08	3.42	3.67	3.80	3.92
		1.08 - 1.67	3.30	3.67	3.88	4.03
		1.67 - 2.50	3.25	3.68	3.85	3.96
		2.50 - 3.33	3.19	3.50	3.64	3.68
		3.33 - 5.00	2.68	3.98	3.29	3.48
		>5.00	2.94	3.21	3.41	3.56
2. New York/New Jersey	Bituminous	<0.80	3.34	3.52	3.62	3.74
		0.80 - 1.08	3.20	3.41	3.51	3.63
		1.08 - 1.67	3.10	3.42	3.54	3.66
		1.67 - 2.50	2.94	3.22	3.35	3.47
		2.50 - 3.33	2.87	3.14	3.22	3.31
		3.33 - 5.00	2.39	2.71	2.90	3.14
		>5.00	2.60	2.83	2.97	3.13
3. Middle Atlantic	Bituminous	<0.80	2.93	3.20	3.34	3.45
		0.80 - 1.08	2.77	3.05	3.17	3.30
		1.08 - 1.67	2.60	2.96	3.11	3.25
		1.67 - 2.50	2.40	2.74	2.88	3.00
		2.50 - 3.33	2.41	2.70	2.82	3.04
		3.33 - 5.00	1.98	2.50	2.81	2.96
		>5.00	1.77	2.14	2.32	2.54
4. South Atlantic	Bituminous	<0.80	2.92	3.32	3.47	3.66
		0.80 - 1.08	2.74	3.12	3.26	3.42
		1.08 - 1.67	2.55	2.60	3.03	3.31
		1.67 - 2.50	2.30	2.80	3.06	3.17
		2.50 - 3.33	2.64	2.53	2.55	2.70
		3.33 - 5.00	2.09	2.69	2.81	2.96
		>5.00	2.52	2.64	2.71	2.87
5. Midwest	Bituminous	<0.80	3.13	3.39	3.53	3.66
		0.80 - 1.08	2.94	3.22	3.37	3.48
		1.08 - 1.67	3.00	3.14	3.30	3.45
		1.67 - 2.50	2.70	2.97	3.08	3.21
		2.50 - 3.33	2.59	2.91	3.02	3.14
		3.33 - 5.00	2.18	2.46	2.78	2.91
		>5.00	2.23	2.42	2.52	2.67
	Sub-Bituminous	<0.80	2.63	2.84	2.84	2.92
		0.80 - 1.08	2.63	2.84	2.84	2.92

TABLE 6.4--Continued

Demand Region	Coal Type	Sulfur Content ($lb SO_2/MMBtu$)	1985	1990	1995	2000
6. Southwest	Bituminous	<0.80	2.94	3.31	3.58	3.77
		0.80 - 1.08	2.89	3.26	3.51	3.69
		1.08 - 1.67	1.03	2.65	3.02	3.16
		1.67 - 2.50	2.71	3.09	3.19	3.21
		2.50 - 3.33	2.57	2.79	2.94	3.08
		3.33 - 5.00	2.95	3.17	3.39	3.46
		>5.00	2.82	2.84	2.97	3.07
7. Central	Bituminous	<0.80	2.77	2.97	3.09	3.14
		0.80 - 1.08	2.76	2.95	3.07	3.09
		1.08 - 1.67	2.95	3.23	3.34	3.46
		1.67 - 2.50	2.95	3.22	3.18	3.22
		2.50 - 3.33	2.94	3.15	3.27	3.40
		3.33 - 5.00	2.69	2.61	2.58	2.66
		>5.00	2.34	2.47	2.52	2.58
	Sub-Bituminous	<0.80	2.53	2.60	2.72	2.81
		0.80 - 1.08	2.53	2.60	2.72	2.81
		1.08 - 1.67	2.37	2.44	2.52	2.81
		1.67 - 2.50	2.43	2.48	2.63	2.54
8. North Central	Bituminous	<0.80	1.64	1.87	1.92	2.01
		0.80 - 1.08	1.47	1.66	1.74	1.76
		1.08 - 1.67	1.29	1.34	1.35	1.38
		1.67 - 2.50	1.91	1.40	1.50	1.54
	Sub-Bituminous	<0.80	1.52	1.62	1.59	1.75
		0.80 - 1.08	1.36	1.48	1.47	1.59
		1.08 - 1.67	0.86	0.92	1.01	1.12
		1.67 - 2.50	0.80	0.90	1.04	1.06
9. West	Bituminous	<0.80	2.69	2.87	2.91	3.15
		0.80 - 1.08	2.63	2.76	2.82	2.98
		1.08 - 1.67	2.26	2.49	2.85	2.91
		1.67 - 2.50	2.53	2.78	2.60	2.65
	Sub-Bituminous	1.67 - 2.50	2.34	2.42	2.49	2.59
10. Northwest	Bituminous	<0.80	3.18	3.37	3.42	3.58
		0.80 - 1.08	3.10	3.24	3.30	3.42
		1.08 - 1.67	2.17	2.27	3.29	3.42
		1.67 - 2.50	2.80	2.81	2.78	2.80
	Sub-Bituminous	<0.80	2.06	2.14	2.29	2.36
		0.80 - 1.08	2.06	2.14	2.29	2.36
		1.08 - 1.67	2.05	2.10	2.29	2.36
		1.67 - 2.50	2.05	2.05	2.05	2.10

---

[a] By ICF Inc., 1850 K Street, N.W., Washington, D.C., 20006.

[b] Taken from Reference 4.

Waste Pretreatment Costs

The cost to pretreat a hazardous waste stream to make it suitable for firing in an industrial boiler offsets the money saved in fuel replacement and alternate disposal costs. Estimating the magnitude of this offsetting cost requires cost data for the typical pretreatment systems being employed. EPA collected preliminary data concerning facilities pretreating wastes used as boiler fuel in an OSW Burner Questionnaire Survey. This was followed up by a telephone survey of 11 facilities pretreating wastes.

Results of these initial efforts indicate that four basic types of pretreatment are practiced: blending, solids removal, water removal, and heating the waste to adjust the viscosity. Blending of a waste stream with either a conventional fuel or another compatible waste stream is used to upgrade it to the quality required by the particular boiler design. This is commonly done to reduce the concentration of metals, solids, water, or halogens, and/or to increase the heating value. Solids are being removed to prevent plugging of the burner gun and to meet particulate emission standards if they are inorganic. Water reduces the caloric value of the waste and can cause burner flame instability. Viscous wastes must be heated to make them pumpable and to permit proper atomization necessary for high combustion efficiency.

Wastes requiring more extensive pretreatment than the four basic types listed above are generally disposed of by alternate means. Many wastes simply cannot economically be made suitable for firing a boiler, i.e., inorganic wastes.

The type of equipment used for blending, solids and water removal, and thermal pretreatment is generally extremely simple. This equipment was described in Section 4. Costs follow for a typical equipment arrangement for each of the four pretreatment processes. These costs are developed for the range of waste flow rates considered representative of those being fired in industrial boilers. The flow rates given in the developed cost curves below are the rates of treated waste leaving the pretreatment process.

The following includes a subsection on the desired waste fuel characteristics for effective operation and discussions of the four pretreatment costs identified above.

Waste Fuel Characteristics for Effective Boiler Operation

Fuel characteristics can have significant effects on boiler operation, such as:

- Deterioration of boiler tubes and refractories
- Excessive emission levels
- Reduced combustion efficiency
- Increased maintenance requirements

However, the range of boiler sizes and types, combined with the range of available waste fuels, generally make it impossible to set specific limits on fuel paramenters. Each case must be based on a separate economic evaluation, considering cost of various levels of fuel pretreatment; of boiler operating cost, including possible reduction in steam production; and of possible flue gas pollution control techniques.

The effects of several fuel characteristics on boiler operation will be discussed below.

Chlorides and Halides. Several sources (References 6,7) have indicated that they prefer to keep the concentrations of chlorides and halides below 0.5 - 1.5%. However, other sources (References 8,9,10,11) have indicated that the actual corrosive effect may depend on boiler operating techniques and the final form which the halides will take. If the ash contains enough free alkali, the resulting chloride salts may cause severe fluxing of the boiler refractories and deterioration of some types of alloy boiler tubes. The corrosive effect also depends on boiler design parameters which govern the probability of ash impingement on boiler surfaces while the ash is still hot enough to be soft and adhere to the surfaces.

High levels of chloride salt, may also form a mist of fine particles, contributing to stack opacity. Dilution of the waste fuel is the only way to reduce chloride concentrations.

The primary effect of releasing halides as acids will be the possibility of increased corrosion of ductwork and equipment handling stack gases if the gas temperature falls below the dew point. This can be avoided by first warming the boiler, using a non-corrosive fuel, then introducing the waste solvent, and monitoring the stack to assure that the temperature does not fall below the dew point.

Sulfur. Although excess sulfur in the waste fuel may not be found very often, if burned it will cause corrosion in ductwork and equipment handling combustion gases if the gas temperature falls below the dew point. This can be avoided if the boiler is first heated using a suitable fuel, and if the stack gas temperature is monitored (Reference 9). Alternatively, high sulfur content waste may be co-fired with low sulfur waste or fuel to reduce the sulfur concentrations of the boiler feed (Reference 6).

High sulfur levels in the waste solvent will also cause excessive levels of SO_2 in the boiler emissions.

Sediment and Particulate Matter. High levels of sediment and particulate matter will increase apparent viscosity of the waste solvent, cause blockage of filters or burner nozzles, settle in waste solvent lines, and may (if not incinerated) cause increased opacity of the stack gas. If particle size is below 100 mesh, and piping is properly designed, wastes containing 5% or more solids may be fed to the boiler. Effects on emissions depend on boiler design and stack gas treatment, as well as the contributing effects of ash in the waste. This will be discussed in the next section.

Ash. Effects of ash, combined with uncombusted particules, include fouling the tubes (Reference 7), slagging the furnace walls (References 8, 9), and increasing opacity of the emissions. These effects can vary widely, depending on actual composition of the ash, design of the boiler, and stack gas treatment. Boilers designed for natural gas or distillate fuels may be significantly affected because they are not equipped with soot blowing provisions, but there may be little effect in boilers designed for residual or solid fuels (Reference 9). Although not definitive, ash fusion-temperature tests may permit some prediction of boiler effects, but test firing in the actual boiler, or in a similar boiler at the manufaturer's facility, is the best way to determine the effects of a given fuel on a given boiler.

Moisture. It is of primary importance that the boiler fuel be a single phase or a stable emulsion. Feeding a two-phase mixture might result in rapidly alternating feed compositions. The results can vary from flame failure to rapid, almost explosive, heat release.

Even when the water and organic components of the waste are miscible, there are two other effects which must be watched: decrease in flue gas dew point, and decrease in boiler efficiency. Moisture in the fuel will appear in the stack, and the higher the moisture level, the lower the dew point of the stack gas. Unless care is taken, there might be a sudden increase of corrosion in stack ducting and equipment.

Very high moisture levels also lower boiler efficiency. Heat required to vaporize the moisture is carried to the stack, and, as a result, furnace temperature is lowered, resulting in reduced heat transfer through the boiler tubes. These effects can be minimized by limiting the waste fuel rate to about 5% of the total fuel rate. With this proviso, there is no limit to the moisture content of the waste fuel; the primary fuel will produce enough heat to vaporize and incinerate the waste while meeting the steam demand.

Viscosity

If viscosity of the waste fuel is too high, it will not be possible to atomize the liquid into droplets small enough to oxidize completely. Good atomization can usually be achieved if waste fuel at the burner is less than 750 SSU (Reference 12). Heaters are available which can heat the fuel as high as 500°F (260°C) to reduce viscosity.

Reasonable pump designs and piping pressure drops set limitations of waste fuel viscosity at about 10,000 SSU. It is practical to maintain storage temperature at 200°F (95°C).

Thus, the limitations on viscosity are:

- 750 SSU at 500°F
- 10,000 SSU at 200°F

Fuel Composition

Smaller boilers are usually equipped with simple controls which link the combustion-air dampers with the fuel control valve (Reference 6). Significant changes in fuel composition will cause fluctuation in the required fuel:air ratio. If too little air flows through the boiler, CO concentration in the stack gas will increase, and combustion efficiency will decrease. One technique to avoid this problem is to set waste fuel feed at a constant flow rate, to supply no more than 30% of the expected heat load. Primary fuel flow is varied to supply the required total heat load, and combustion air flow is set to assure that there will be adequate air throughout the boiler firing range, and for all expected waste fuel compositions.

Larger boilers are usually equipped with combustion controls which can permit firing 100% waste fuel if the heat of combustion is high enough to sustain a good flame, if fire box temperatures are high enough to insure adequate combustion, and if heat realease is adequate to supply steam demand.

Pretreatment Cost

Blending Costs. A blending system consists of three tanks, each equipped with an agitator. Tank size is a function of waste fuel throughput and expected blending time. Because one tank would be required as a dry tank, additional capital costs for blending are based on two storage tanks and three agitators. These costs are shown below.

Capital Costs - Blending

Tank Size (gal)	Installed[a] Capital Cost ($)
1,000	12,000
2,000	20,000
5,000	30,000
10,000	51,000
20,000	80,000

---

[a] Two tanks and three agitators.

Thermal Treatment. Although there is an infinite range of possible liquid wastes which might be burned, the techniques for introducing the wastes into the boiler are similar, and are based largely on techniques already developed for burning conventional fuels: The liquid must be sufficiently atomized to permit fairly rapid combustion. The resulting flame must be as long as possible to minimize flame temperature and to minimize formation of NO_x, but the flame must not touch the boiler refractories, walls, or tubes unless the boiler is specifically designed for such contact. Although good atomization may be achieved with fluid vicosities as high as 5,000 SSU (Reference 12), it is common practice with standard fuel oils to limit viscosity to 750 SSU at the burner nozzle. Pumping problems increase with liquid viscosity, and common practice with fuel oils is to maintain viscosity below 10,000 SSU for storage and transfer, with additional heat supplied just before the burner to further lower the viscosity.

For purposes of developing thermal pretreatment costs, liquid wastes have been categorized into three groups according to their viscosity:

1. Viscosity at ambient temperature ≤750 SSU.
2. Viscosity at ambient temperature is between 750 and 10,000 SSU.
3. Viscosity at ambient temperature ≥10,000 SS, but <10,000 SSU, at 200°F.

If the viscosity is less than or equal to 750 SSU, the waste is both pumpable and capable of being properly atomized. No thermal treatment is needed for wastes in this category. Wastes of viscosity between 750 and 10,000 SSU are pumpable but must be heated to achieve satisfactory atomization. A fuel heater (shell and tube heat exchanger) may be used to raise the liquid temperature sufficiently to lower the viscosity to below the limit for good atomization (750 SSU). An equipment arrangement for this purpose is shown schematically in Figure 6.1. In this scheme, the waste is heated (by steam) as it pases through the heat exchanger before entering the boiler. The only thermal treatment equipment items needed are the heater and piping. The installed costs of this equipment are plotted as a function of waste feed rate in Figure 6.2 as curve 1.

Wastes of greater than 10,000 SSU viscosity at ambient temperature must not only be treated to insure good atomization, but must also be kept hot enough to prevent them from setting up in the storage tank and piping. Equipment requirements for waste in this category include the heat exchanger for heating the waste as it is pumped to the boiler, provisions to recirculate the waste back to the storage tank, as well as items to keep the liquid warm:

- Storage tank insulation
- Storage tank heaters
- Pipe tracing and insulation
- Addition of a spare circulating pump

Installed costs of this equipment, excluding the storage tank insulation and heaters, are plotted as a function of waste throughput in Figure 6.2 as curve 2. Because ES is not supplying waste storage costs, the tank heater and insulation costs are being provided as separate cost items. These costs are presented in Table 6.5. The storage tank heater for which costs are presented here is the immersion steam coil type. Insulation costs are for three inches of fiberglass insulation.

Solids Removal Cost. As discussed in Section 4, sludges and slurries are generally not pretreated to reduce the solids content to levels where the liquid can be burned in an industrial boiler but, rather, are mixed with solid fuels (coal or non-fossil fuels) before firing in a solid fuel unit. For the solids removal system priced below, an upper limit on solids content of 5% by weight is used. Wastes of higher solids content will probably be disposed of by alternate means.

A typical solids removal system will include either both settling and screening or settling and filtration. A typical system is illustrated by Figure 6.3. In this scheme, the waste is first pumped from a processing unit into one of three tanks. The three tanks are alternately used in either a receiving mode, a holding mode to provide a quiescent environment for settling, or a transfer mode from which the supernatant waste is pumped to final solids removal by either screening or filtering. A duplex basket type

FIGURE 6.1

BLOCK DIAGRAM, THERMAL TREATMENT FOR LIQUIDS
IN THE RANGE OF 750 - 10,000 SSU AT AMBIENT TEMPERATURE

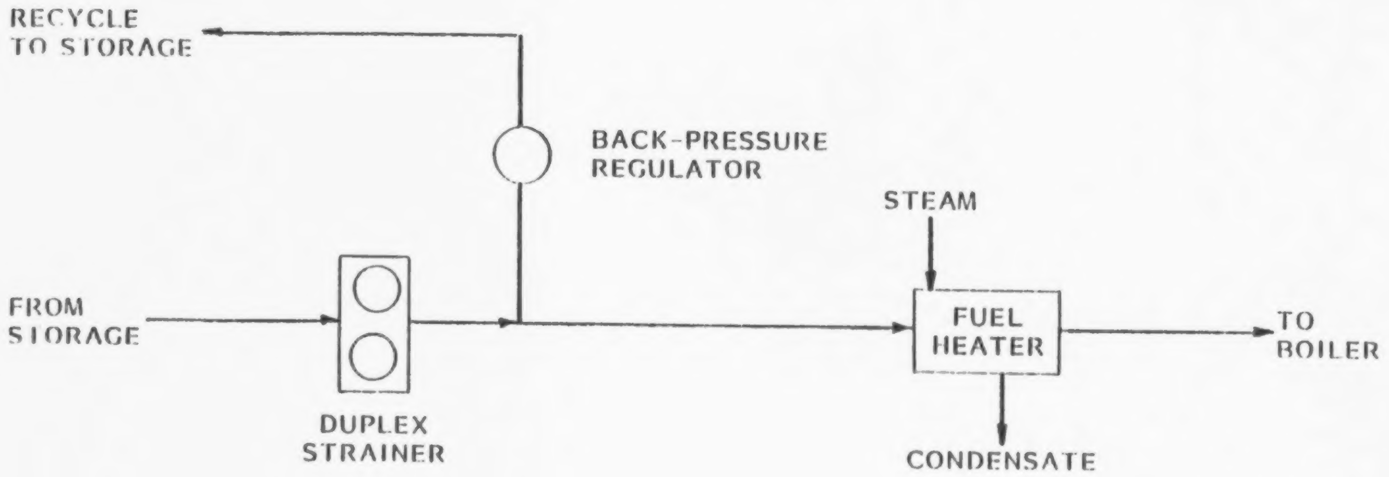
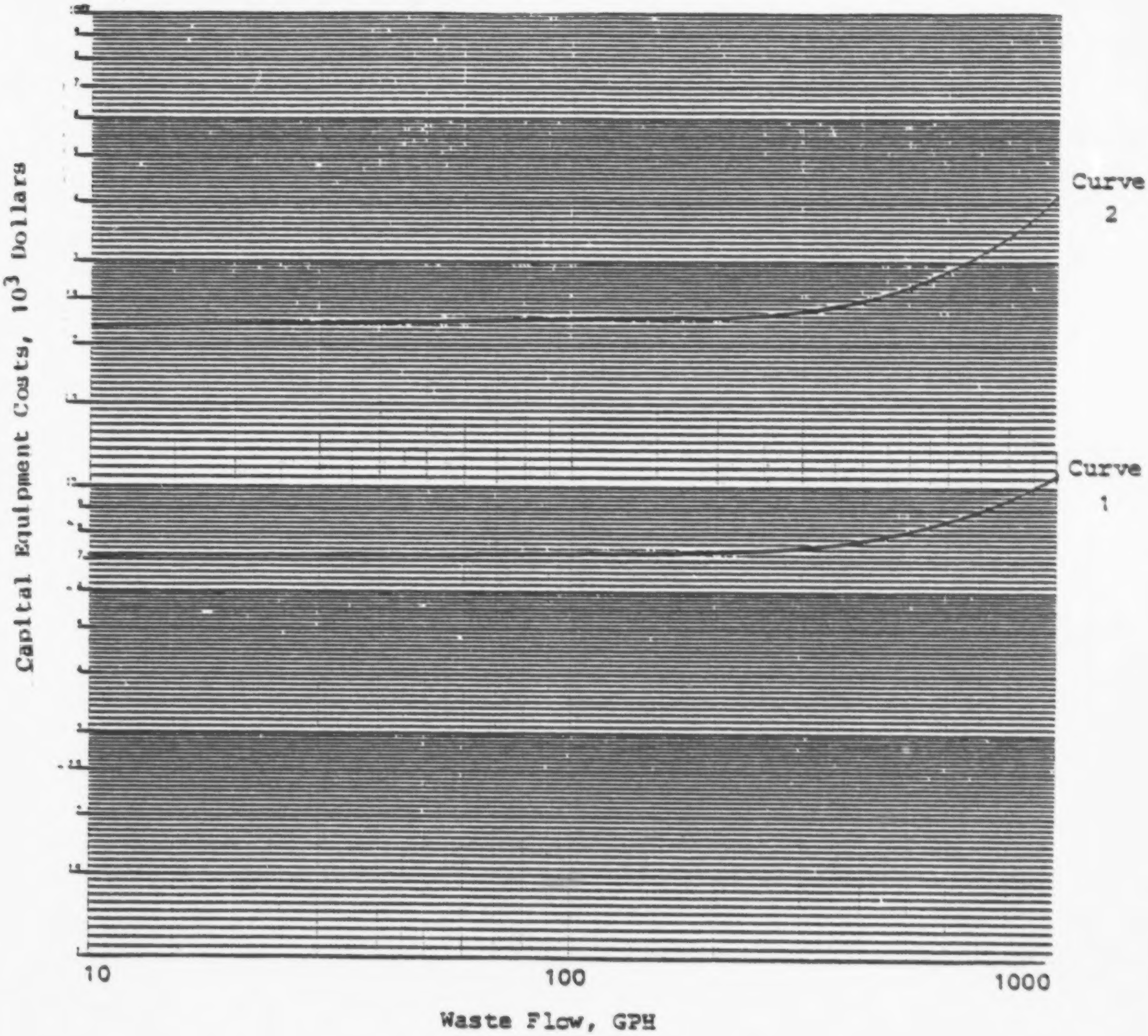

RECYCLE
TO STORAGE
BACK-PRESSURE
REGULATOR
STEAM
FROM
STORAGE
FUEL
HEATER
TO
BOILER
DUPLEX
STRAINER
CONDENSATE

FIGURE 6.2

THERMAL TREATMENT EQUIPMENT COST
AS A FUNCTION OF WASTE FLOW RATE



Curve 1: Pumpable at ambient temperatures but must be heated for good atomization.

Curve 2: Must be heated to keep pumpable and to obtain good atomization.

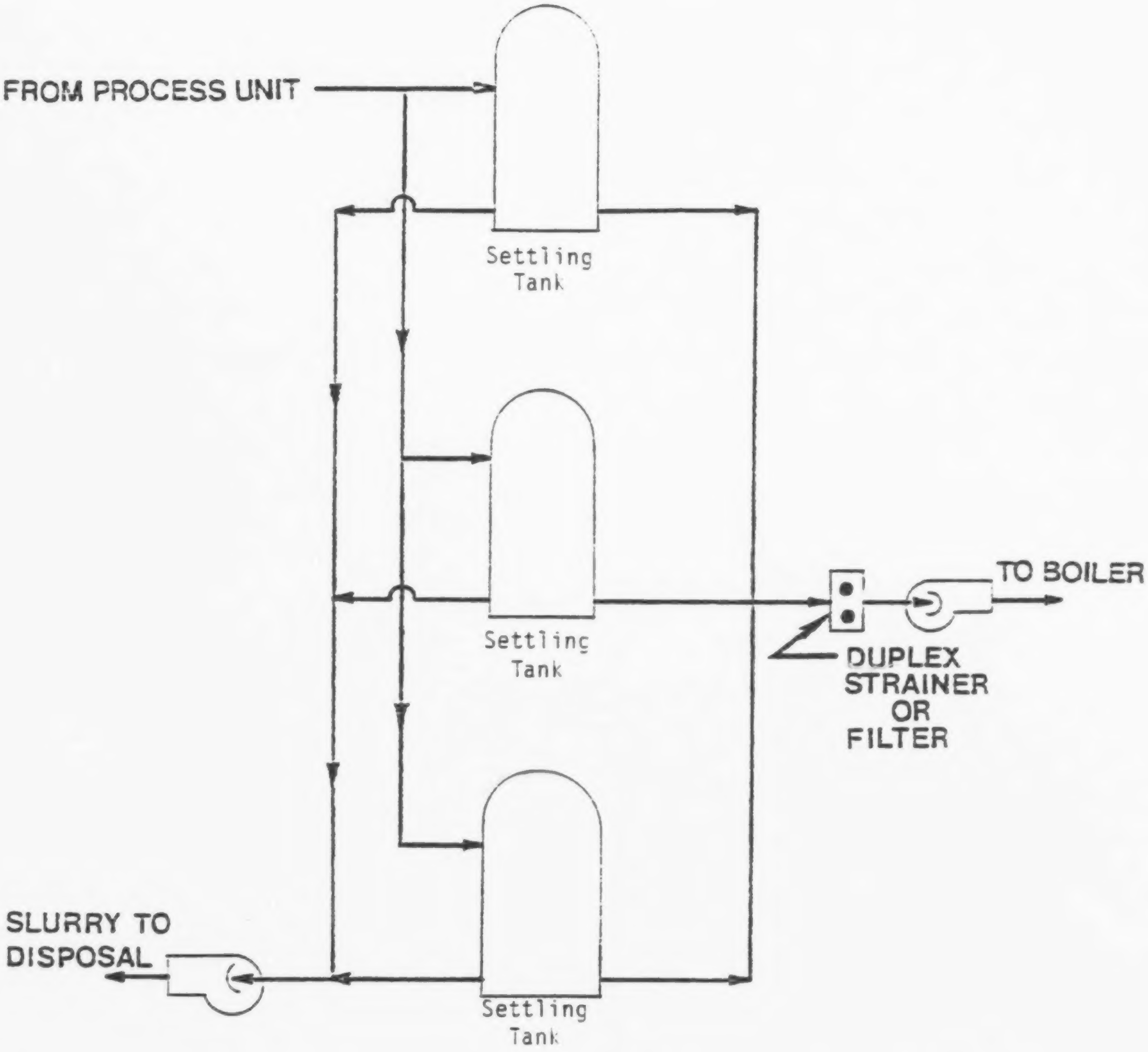
TABLE 6.5

STORAGE TANK HEATER AND INSULATION INSTALLED COSTS

Tank Size (gal)	Heater Costs ($)	Insulation Costs ($)
500	11,000	430
1,000	12,000	660
2,000	14,000	960
5,000	17,000	1,310
10,000	19,000	2,850
20,000	38,000	3,640

FIGURE 6.3

TYPICAL SOLIDS REMOVAL SYSTEM


FROM PROCESS UNIT
Settling Tank
Settling Tank
TO BOILER
DUPLEX STRAINER OR FILTER
SLURRY TO DISPOSAL
Settling Tank

strainer (100 mesh) is commonly used when the polishing stage is achieved by screening. A dual cartridge filter is generally the choice if a filter is used. Either of these devices permits cleaning without process shutdown.

The cost for this type system is shown in Figure 6.4 as a function of the throughput of treated waste. In developing this curve, it was assumed that waste entering the system contained 5% solids by weight as mentioned above. The capital costs should be essentially independent of the solids content for levels below 5%. The system shown in Figure 6.3 is capable of reducing the solids content down to levels where no plugging of the burner gun nozzle occurs, which is probably between 0.5 to 1%.

The equipment items included in the cost development are the tanks, pump, piping, and a cartridge type filter. Since a duplex screen is generally less expensive than a filter, a filter was assumed in developing the cost curve. The tanks are above ground, vertical, conical roof of carbon steel construction with concrete support pad. They were sized to provide a detention time of approximately 10 hours which should provide sufficient settling time for most nonviscous wastes. The costs estimate includes only two of the three tanks shown in Figure 6.3 because a waste holding tank is generally used when no pretreatment is required. A Moyno® pump is assumed for removal of the sludge or slurry formed by the settled solids. It is assumed that this sludge/slurry is either pumped into a tank truck, drums, or a cart for transport to safe disposal.

Water Removal Costs

Decanting was the only means of removing water from wastes fired in boilers reported by those contacted during the telephone survey. This process only removes the water in excess of the solubility limit in the organic fraction of the waste. Standard above ground cylindrical storage tanks are used as decanting devices. A typical arrangement is depicted schematically in Figure 6.5 and is very similiar to that used for removing solids.

The total installed capital costs for this type of system were developed as a function of the dewatered waste flow rate. These costs are presented in Figure 6.6. Costs are presented for three different assumed inlet water contents: 10, 50, and 75% by weight. It was assumed that the water content of the waste is reduced to 5% by weight. This level of water should not cause any significant adverse effects on the boiler.

Equipment items included in the costs are two tanks, a pump for transferring the decanted water, and piping. Because a holding tank is often used when no pretreatment is required, one of the three tanks shown in Figure 6.5 is not included in the cost estimates. Similarly, the duplex strainer and pump for transferring the treated waste to the boiler are required if there is no dewatering and, therefore, are also not included. The tanks are cylindrical, above ground, conical roof design of carbon steel construction with a concrete support pad. They are sized to provide approximately 10 hours detention time which should be adequate for dewatering most wastes where decanting is practical. A gear pump of carbon steel construction was assumed for removing the water from the tank. It was sized to remove the water layer in less than one hour.

FIGURE 6.4

SOLIDS REMOVAL EQUIPMENT COST AS
A FUNCTION OF WASTE FLOW RATE

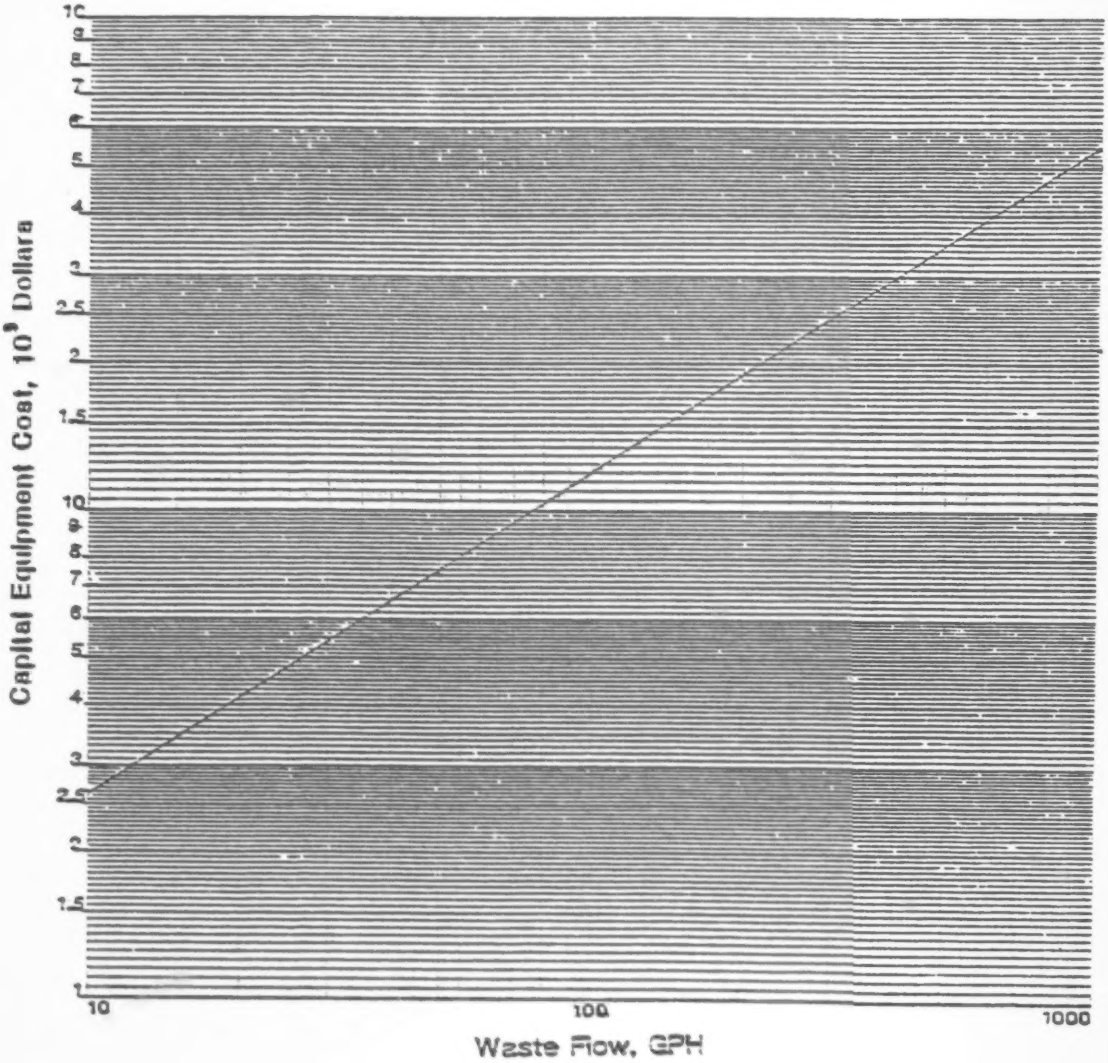


FIGURE 6.5

TYPICAL WATER REMOVAL SYSTEM

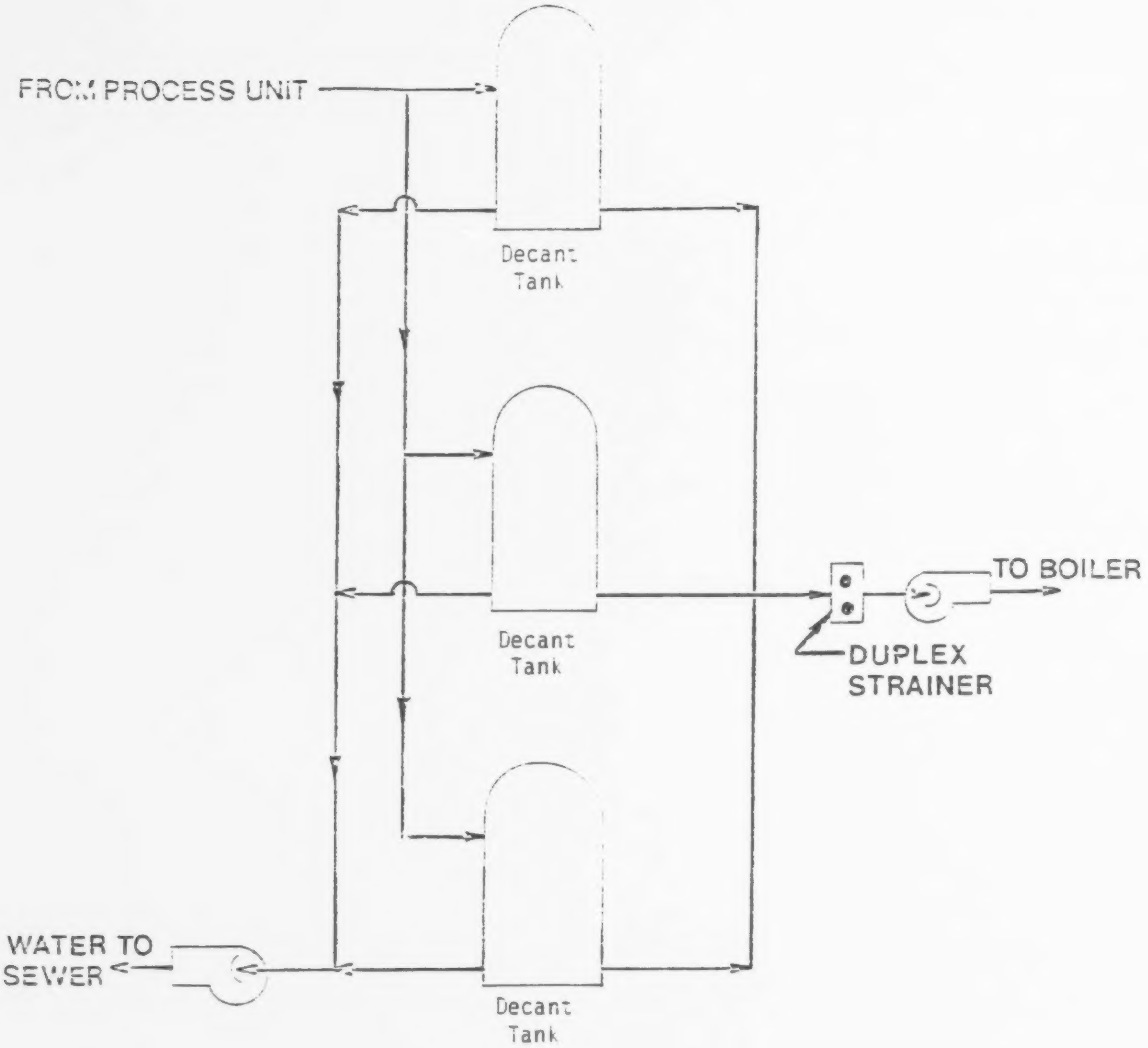
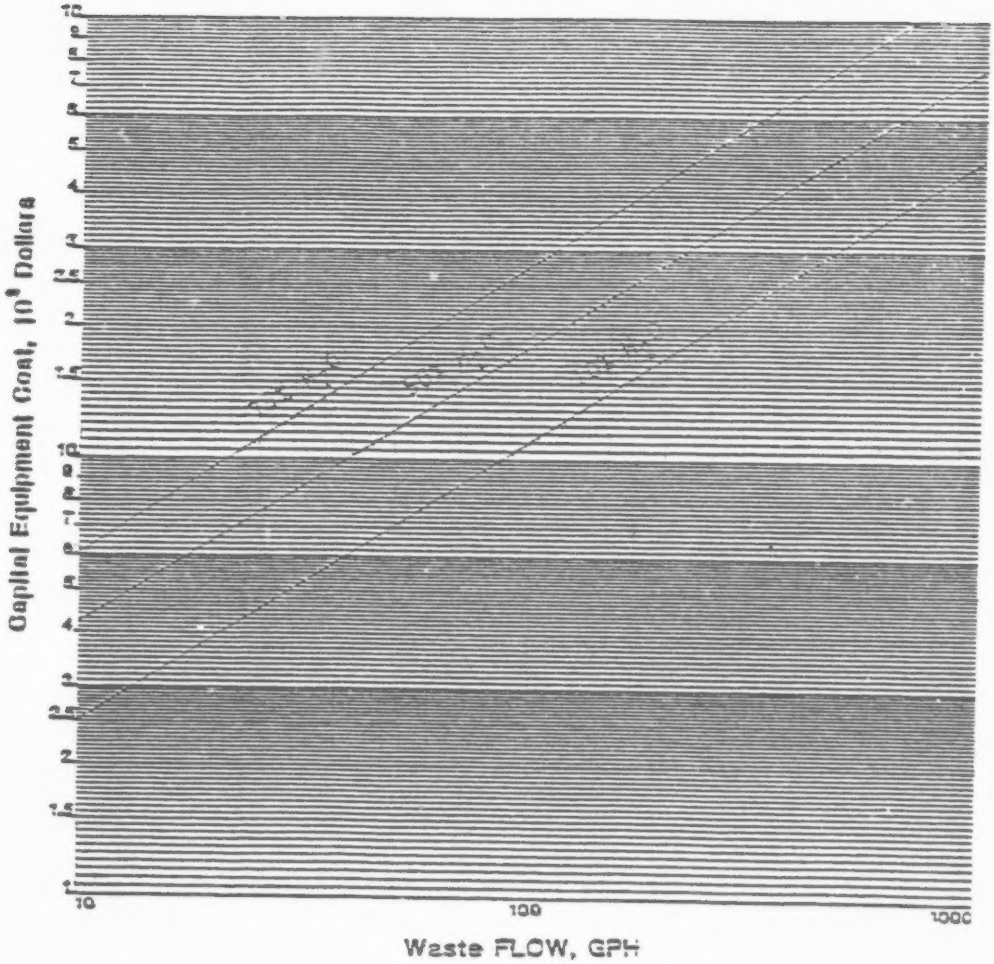

FROM PROCESS UNIT
Decant Tank
Decant Tank
TO BOILER
DUPLEX STRAINER
WATER TO SEWER
Decant Tank

FIGURE 6.6

WATER REMOVAL EQUIPMENT COST
AS A FUNCTION OF WASTE FLOW RATE



Boiler Modification Costs

Burner Modification Costs

The cost for modifying an existing burner system to provide for firing hazardous waste is extremely site specific and depends on the existing burner type and capacity, number of burners employed, type of conventional fuel fired, properties of the waste, and quantity of waste to be fired. Generally, the least expensive approach is taken. Some boilers were originally designed to fire hazardous waste as either the primary or as the supplemental fuel. Others require only that a burner gun be replumbed to fire the waste. This would not require significant capitial expenditure. In many other instances, the hazardous waste is blended with the conventional fuel and fired with no modifications being made to the burner. This is the basic approach used when burning solid wastes in coal-fired boilers.

Costs given here are for providing the necessary burner components to fire a gaseous or liquid hazardous waste in natural gas, oil, coal, and combination fossil fuel-fired boilers. Solid hazardous waste firing is not extensively practiced and is generally limited to coal-fired units where it is blended with the coal before being fed to the boiler. All costs given below assume that the waste is piped to the burner, i.e., costs do not include a fuel handling train. They are based on prices obtained from boiler burner vendors and therefore may be higher than actual costs as many large industrial boiler owners fabricate their own waste burners.

There are two basic alternatives commonly practiced for burner system retrofit to accomodate waste firing that require significant captial expenditures. The first alternative is to install additional burner guns for waste firing in the air register of the existing burner(s). Waste is simply atomized into the primary fuel (natural gas or oil) flame envelope. In boilers equipped only with ring burners for natural gas, liquid waste co-firing can be effected by plumbing a liquid waste nozzle into the burner centerline in much the same fashion that these burners are retrofitted for fuel oil firing. For safety reasons, the waste burner gun must be tied into the flame safeguard system to shut off the waste flow in case of flame out. A good quality air or steam atomizing burner gun capable of handling the range of waste flows typically fired in this type arrangement can be purchased for under $5,000. The total installed cost, including plumbing and electrical to tie into the flame safeguard system, can run from $10,000 to $15,000.

In some burner retrofits, replacement of the entire burner assembly may be required. A complete burner assembly includes air register, burner guns, ignitor, flame safeguards and windbox. The number of new burner assemblies installed as part of the retrofit depends on the quantity of waste to be burned and the boiler size. The cost of a single burner assembly depends on a number of factors including the number of fuels/wastes fired (which determines the number of guns), the properties of the fuels/wastes, and the fuel/waste quantities. The small gas and oil fired packaged boilers selected for the economic analysis (15 million Btu/hr heat input) are single burner units. A complete burner assembly for one of these boilers that is capable of firing both oil (or gas) and a liquid hazardous waste typically costs $25,000 to

$30,000 installed. A 150 million Btu/hr heat input oil or gas fired boiler generally has from one to six burners. Therefore, the burners for those units vary from 25 to 150 million Btu/hr heat input. Installed cost of these burner assemblies typically runs from $35,000 to $40,000 for the 25 million Btu/hr unit to $75,000 to $90,000 for the 150 million Btu/hr unit. A large field erected oil fired boiler of 400 million Btu/hr heat input generally has four or more burners. Therefore, costs for the individual burner assemblies should be about the same as those for a 150 million Btu/hr heat input boiler.

Replacement of a complete assembly for a pulverized coal-fired boiler to provide for hazardous waste burning is unlikely because it is almost always possible to insert some type of waste gun in the air register of one of these units. Furthermore, many of these units also have oil or gas guns that can be replumbed for firing the waste. For the size pulverized coal boilers selected for the economic analysis, the burners are most likely between 35 to 75 million Btu/hr capacity. Installed cost of a complete assembly capable of co-firing a liquid or gaseous waste with the coal typically runs from $75,000 to $100,000. Installation typically is 50% of the equipment costs.

Stoker boilers are purchased with or without auxillary burners to fire oil or gas. When the boiler does not have a burner that can be retrofitted to burn the waste, a complete burner assembly is necessary. To install a complete burner assembly in the furnace wall of a stoker not having an existing opening to accept it would be extremely expensive because a section of the wall tubes must be removed. This generally requires an expensive engineering study and costs for complete retrofit are estimated to run between $200,000 to $300,000 depending on the boiler and burner designs. If an existing opening can be used, the installed cost would be considerably less per burner assembly. As with the other boiler types described above, the cost would depend on the size of burner assembly installed. If the waste is to be co-fired with the coal, the burner would likely be designed to provide approximately 25% or less of the total fuel requirement. For the 30 million Btu/hr stoker, the maximum capacity burner assembly would be slightly less than 10 million Btu/hr and would typically cost $20,000 to $25,000 installed. For the 75 and 150 million Btu/hr stoker models, one or two burners may be used. A single 25 million Btu/hr burner costing approximately $35,000 to $40,000 installed would be representative for the 75 million Btu/hr boiler. For the 150 million Btu/hr stoker boiler, the burn assembly retrofit is likely to cost $60,000 to $70,000 regardless of whether one or two units are used to supply up to 25% of the total heat input.

Oxygen and Carbon Monoxide Monitoring

Continuous monitoring of O_2 and CO concentration in the exhaust gases of a boiler burning a hazardous waste may be necessary to insure that good combustion conditions are being maintained. Many boilers are already equipped with O_2 and/or CO monitoring as components of automatic excess air trim systems. These systems were purchased primarily to save fuel costs through increased combustion efficiency. Automatic excess air systems are becoming increasingly common on new boilers of all types (Reference 3). Furthermore, one of the requirements of the new source performance standards for industrial boilers being considered is that either O_2 or CO_2 monitoring be installed to measure the amount of diluent air leaking into the stack gases (Reference 14).

The cost of both O_2 and CO continuous emissions monitoring systems vary depending on vendor and type (in-situ or extractive). This variation is insignificant, however, for the level of accuracy needed for the economic analysis. Therefore, a single cost figure is given for each monitoring system. The cost data presented here were developed using engineering judgment and prices obtained from vendors, and reference costs were for the 1983 period.

Typically, an installed oxygen monitoring system costs approximately $15,000 including analyzer, sample transport and conditioning system (if an extractive type), strip chart recorder, and installation. This cost is essentially independent of boiler size and type.

Carbon monoxide monitoring systems are more expensive than O_2 systems because a more sophisticated analyzer is required. A representative cost for an installed CO monitoring system is $20,000 including the CO analyzer, a sample transport and conditioning system (for an extractive type), a strip chart recorder, and installation. As with the O_2 system, this cost should be independent of boiler size and type.

The above costs assume that the collected strip chart data will be reduced manually. For an additional $20,000 an automatic data reduction system can be provided (Reference 14).

Furnace Temperature Monitoring

One basic strategy for regulating the combustive destruction of hazardous waste in boilers is to set performance goals that must be met by the equipment. The ability of the combustor to generate a specific environment (time, temperature, turbulence) is one of several performance goals being considered as part of an approach for regulating the burning of hazardous waste in boilers. If this performance goal is adopted, some means of monitoring the boiler furnace temperature may be required.

One or more thermocouples will be needed to monitor the temperature in the hot environment of a boiler furnace. A pryometer is not capable of sufficient accuracy. The thermocouple must be capable of measuring temperatures in the range of 2000 to 3000°F and, therefore, should be radiation shielded. If more than one thermocouple is required, a scanner is recommended to alternately switch to each thermocouple. A simple strip chart recorder is adequate for providing a permanent record of thermocouple ouput. A linearizer with reference junction compensation is necessary. This can be either a separate device or built into the strip chart recorder. Sufficient thermocouple wiring is needed to link the various components. Total cost of this type of monitoring system is typically $4,000. These costs are based on prices obtained from Reference 15. Installation should be less than $1,000. These costs should be relatively independent of boiler size and type.

Waste Feed Metering. If limitations on the hazardous waste feed rate are adopted, capital outlays for flow metering will be necessary. Liquid, gaseous, or both types of flow meters will be needed, depending on the waste fired. Two types of liquid flow measurement devices well-suited for this application are the positive displacement meter and the orifice meter. These units are relatively inexpensive and are applicable to a wide range of wastes. Either device can be obtained for approximately $2,000 to meter flows up to 2,400 gallons per hour, which is the maximum flow rate one would anticipate for waste feed to an industrial size boiler. (A 400 million Btu per hour heat input boiler fires approximately 2,400 gallons per hour of residual fuel oil at full load.) Some type of recording is needed to provide a permanent record of the waste feed rate. A simple $2,000 strip chart would serve this purpose adequately. Installation is likely to cost an additional $1,000. Thus, the total installed cost of a liquid waste feed metering system will be approximately $5,000.

Three types of meters which should cover the range of gaseous waste applications are the turbine meter, the vortex shedding meter, and the orifice meter. Orifice meters result in a large permanent pressure drop and, therefore, are limited to applications where such large pressure drops can be tolerated. Both the turbine and vortex shedding meters are low pressure drop devices. A turbine meter or vortex shedding meter capable of measuring gas flow rates up to 30,000 standard cubic feet per hour costs approximately $6,000. Most hazardous waste streams fall within this flow range. An orifice meter capable of measuring flows up to 30,000 standard cubic feet per hour costs approximately $3,000 including all the ancillary items (pressure transducers, etc.). A recording device for any of these devices can be purchased for approximately $2,000. Installation should cost less than $1,000. Therefore, the total installed cost of a turbine or vortex shedding metering system might typically cost $9,000 and an orifice meter system might cost $6,000.

Process Control Instrumentation

As with burner gun assemblies, the costs to retrofit the combustion control instrumentation to permit the firing of hazardous waste is very site-specific and generally the most economical approach is taken. Because the cost is so site-specific, some generalizations are necessary to tailor them for use in analyzing the economics of incinerating wastes in boilers. For example, the costs presented here include only components necessitated by the addition of waste firing.

For many retrofits of boilers to fire hazardous waste, no significant change to the combustion control instrumentation is required. For instance when a waste is co-fired with a conventional fuel at a rate of less than 25% of the total fuel demand, the general practice is to base-load with waste at a steady feed rate and modulate the conventional fuel only. In this case, the combustion control instrumentation is essentially unaltered. Similarly, when the waste is blended with the conventional fuel before it is fired, there is no combustion control instrumentation modifications required. In situations where the total heat input is provided by waste(s) that can be fired in the same burner(s) already installed on the boiler, there, also, are no significant changes in the combustion controls required.

Installation of a completely new combustion control system is rarely needed to fire hazardous waste. When modulation of the waste feed rate is required, it is almost always achieved by integrating some additional components into the existing system. A possible exception is when the existing system is so antiquated that it is more economical to install a new one than to upgrade it to handle the waste.

The majority of oil, gas, or combination gas/oil boilers of 30 million Btu per hour heat input or less have direct-positioning (jackshaft) type combustion control. Because of its simplicity, this type of control system can easily be modified to integrate modulation of the waste feed. This can easily be done in most applications for less than $5,000 including hardware and installation. Hardware includes waste flow valve, additional control linkage for the jackshaft, and some minor plumbing items.

All other boilers have some form of a metering type combustion control. Hardware necessary to control the combustion of the waste can generally be integrated into this type control system for $20,000 to $30,000, including installation. Hardware includes a setpoint controller, flow control valve, flow metering device, miscellaneous piping, and electrical wiring. The flame safeguard is not considered as part of the control system here because it was included as a burner assembly component.

Air Pollution Control Devices Costs

If EPA promulgates emission standards for boilers firing hazardous waste, similar to those adopted for incinerators it is likely that some boilers may either require the addition of removal equipment for particulate matter and HCl or the reduction of the ash and/or halogen content of the waste to be fired. Air pollution control devices may also be needed to limit the emissions of toxic metals which may be emitted as either fine particles or as vapors. Due to the large capital and operating expense associated with the application of air pollution control devices, it is not likely that burning hazardous wastes will prove economically attractive should these devices be required. Boiler operators are more apt to meet emission standards by either blending the waste to reduce the concentration of the contaminant of concern or find alternate means of disposal. It is impossible, however, to predict with certainty the industry trends relative to the additional air pollution control devices. Therefore, the costs presented in this section are for the control devices that are most likely to be applied should performance standards for particulate matter, metals and/or HCl be adopted.

If control devices are chosen as the means to meet emission standards, then one of three basic systems is likely to be used. For particulate matter control (including metal particles), either an electrostatic precipitator or a baghouse is the likely candidate. The high energy costs associated with scrubbers will limit their use when only particulate matter removal is required. However, a scrubber system is a logical choice for the removal of HCl or vaporous metals. When more than one of the four pollutants (particulate matter, HCl, metal particles, metal vapors) must be removed, a scrubbing system becomes even more attractive.

Capital costs are presented below for each of the three types of air pollution control devices (APCD) as a function of the volume of gas treated. The costs presented here were developed from information obtained from Reference 16 and 17.

The purchased equipment costs provide the basis for estimating the capital APCD costs. Factors used to calculate the capital costs are listed in Table 6.6. These factors represent the individual capital cost components expressed as a fraction of the purchased equipment costs. Direct capital costs consist of the basic and auxiliary equipment costs in addition to the labor and material required to install the equipment. Indirect costs are those costs not attributable to specific equipment items. Each of the control system cost curves presented below include the cost of auxiliary equipment normally associated with such a system.

Electrostatic Precipitator Costs

The electrostatic precipitator is likely to be a primary candidate should a boiler operator only need to install an APCD to meet a particulate matter emission standard. These devices typically have a high particulate matter collection efficiency. Furthermore, they are low pressure drop devices which make them especially well-suited for retrofit applications such as industrial boilers co-firing wastes. Another advantage of being a low pressure drop device is that new fans or other gas handling equipment are not needed. Consequently, the costs presented below include no provisions for a new fan or other gas handling equipment.

Capital costs of electrostatic precipitators are plotted in Figure 6.7 as a function of the exhaust gas treated. These costs were developed using the Deutsch equation:

$$A = -Q \ln (1 - n)/w$$

where: n is the design efficiency specified
w is drift velocity, ft/s
Q is the exhaust flow rate, cfs
A is the net plate area, ft^2

The drift velocity quantifies the electrical characteristics of the dust and, therefore, has a large effect on the collection efficiency and plate area. For these reasons, costs given for drift velocities of 0.115 ft/sec are representative of high-resistivity dust and of 0.282 ft/sec are representative of low-resistivity dusts. High resistivity dust cost data should be used for application to low sulfur containing fuels. Conversely, cost data for low resistivity should be applied for high sulfur containing fuels.

Since they are also a function of the efficiency, ESP costs are reported for two different levels, 99.5 and 99.9%. It is unlikely that efficiencies in excess of 99.9% will be required for this application as it is difficult to routinely achieve higher levels.

The ESP cost curves are for an insulated carbon steel unit since the wastes or waste/fuel mixtures burned may possibly contain significant quantities of water, sulfur, phosphorous, or halogen compounds. The presence of significant quantities of these materials in the fired waste can result in the formation of sulfuric, hydrochloric, or phosphoric acids in the combustion gases. Insulation will keep the temperature of the combustion gases above the dew point of these acids and thus, prevent corrosion of the ESP.

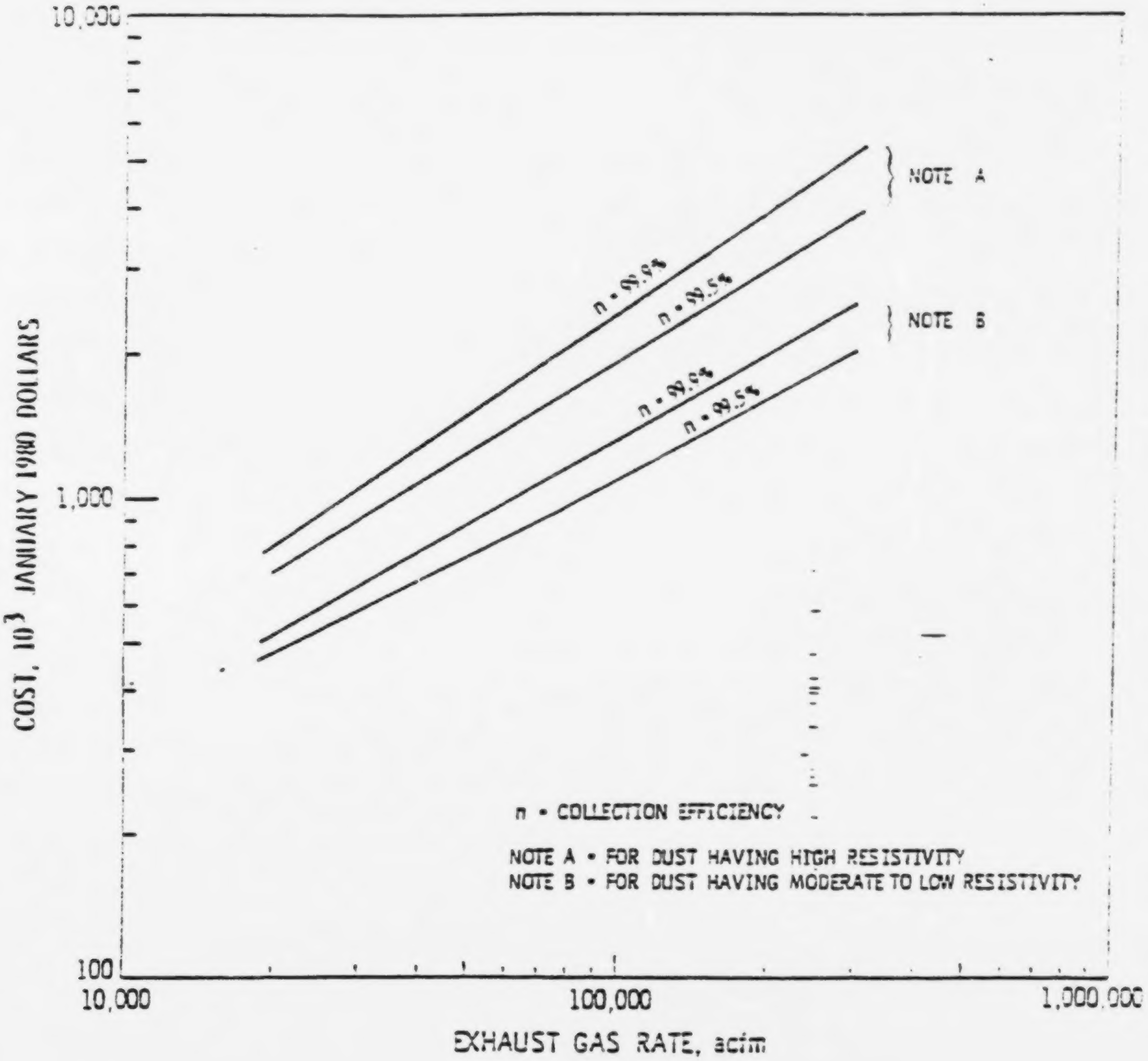
TABLE 6.6

AVERAGE COST FACTORS FOR ESTIMATING CAPITAL COSTS

Cost Factors	ESP	Wet Scrubber	Fabric Filter
DIRECT COSTS			
1. Purchased equipment costs			
a) Control device and auxiliary equipment	0.82	0.82	0.82
b) Instruments & controls	0.10	0.10	0.10
c) Taxes	0.03	0.03	0.03
d) Freight	0.05	0.05	0.05
Subtotal	1.00	1.00	1.00
2. Installation direct costs			
a) Foundations & support	0.04	0.06	0.04
b) Erection & handling	0.50	0.40	0.50
c) Electrical	0.08	0.01	0.08
d) Piping	0.01	0.05	0.01
e) Insulation	0.02	0.03	0.07
f) Painting	0.02	0.01	0.02
Subtotal	1.67	1.56	1.72
INDIRECT COSTS			
3. Installation indirect costs			
a) Engineering & supervision	0.20	0.10	0.10
b) Construction & field expense	0.20	0.10	0.20
c) Construction fee	0.10	0.10	0.10
d) Startup	0.01	0.01	0.01
e) Performance test	0.01	0.01	0.01
f) Model study	0.02	0.0	0.0
g) Contingencies	0.03	0.03	0.03
TOTAL	2.24	1.91	2.17

FIGURE 6.7

CAPITAL COSTS OF ELECTROSTATIC PRECIPITATORS,
CARBON STEEL CONSTRUCTION



Baghouse Costs

Baghouses have increasingly been selected for controlling particulate matter emissions from industrial boilers. These devices are capable of extremely high collection efficiencies and can be used across a broad range of exhaust gas volumes. Reverse air is the most common type baghouse installed on boilers (Reference 18). Therefore, the cost curve presented in Figure 6.7 is for this type of unit. The most commonly chosen bag for boiler application is constructed of fiberglass (Reference 18). Thus, the cost curve presented in Figure 6.8 assumes fiberglass bags are used. An air-to-cloth ratio of 2 to 1 ft/min was used to generate the cost curve. Because baghouses are relatively low pressure drop devices, the costs do not provide for a fan or a fan drive. It is assumed that the existing combustion air fan and/or blowers are capable of pushing the exhaust gases through the baghouse. The cost curve shown in Figure 6.8 is for an insulated carbon steel unit. For this application, the baghouse should be insulated to prevent moisture condensation which could blind bags and to prevent acid dew point corrosion.

Scrubbing Systems Costs

Because of the inherent high operating and maintenance costs associated with scrubbers, it is very unlikely that these devices will be installed to solely meet particulate matter emission limits. A scrubber system is, however, a logical choice for HCl, simultaneous particulate matter and HCl, or simultaneous vaporous metals and HCl removal. For simultaneous HCl and particulate removal, a combination venturi scrubber/acid gas absorber system is likely to be the most economical choice if there is no existing particulate matter APCD. A typical system might include a quench tower, venturi scrubber for particulate collection, acid gas absorber, caustic recycle system, and ID fans plus auxiliaries. The capital costs of this type system is plotted as a function of exhaust gas flow through it as Figure 6.9. This cost curve was developed from Reference 17 and is based on a venturi pressure drop requirement of 30 in. w.c., which is also typical. For high pressure drop systems (approximately 100 in. w.c.), the additional costs for the venturi and multiple, high-head fans frequently double the total system purchase cost. The venturi scrubber comprises approximately 15% of the total system costs. Therefore, multiplying the costs in Figure 6.8 by 85% provides an estimate of an absorptive system capable of removing HCl, metal vapors or both.

OPERATING AND MAINTENANCE COSTS

The operating and maintenance costs for boiler operation are likely to be greater whenever wastes alone or a combination of waste and conventional fuels are burned than when only conventional fuels are burned. Additional storage and handling facilities are typically required to fire wastes. These must be maintained and, if agitators or nitrogen blanketing are used, could increase operating costs also. When the wastes must be pretreated before they can be burned, additional O/M costs are incurred. Additional maintenance of the boiler itself, resulting from the presence of high ash, alkali metals, chlorine, sulfur, or phosphorous compounds in the waste, is another potential incremental cost associated with burning wastes in boilers. The deleterious

FIGURE 6.8

CAPITAL COSTS OF FABRIC FILTERS (REVERSED AIR), CARBON STEEL CONSTRUCTION

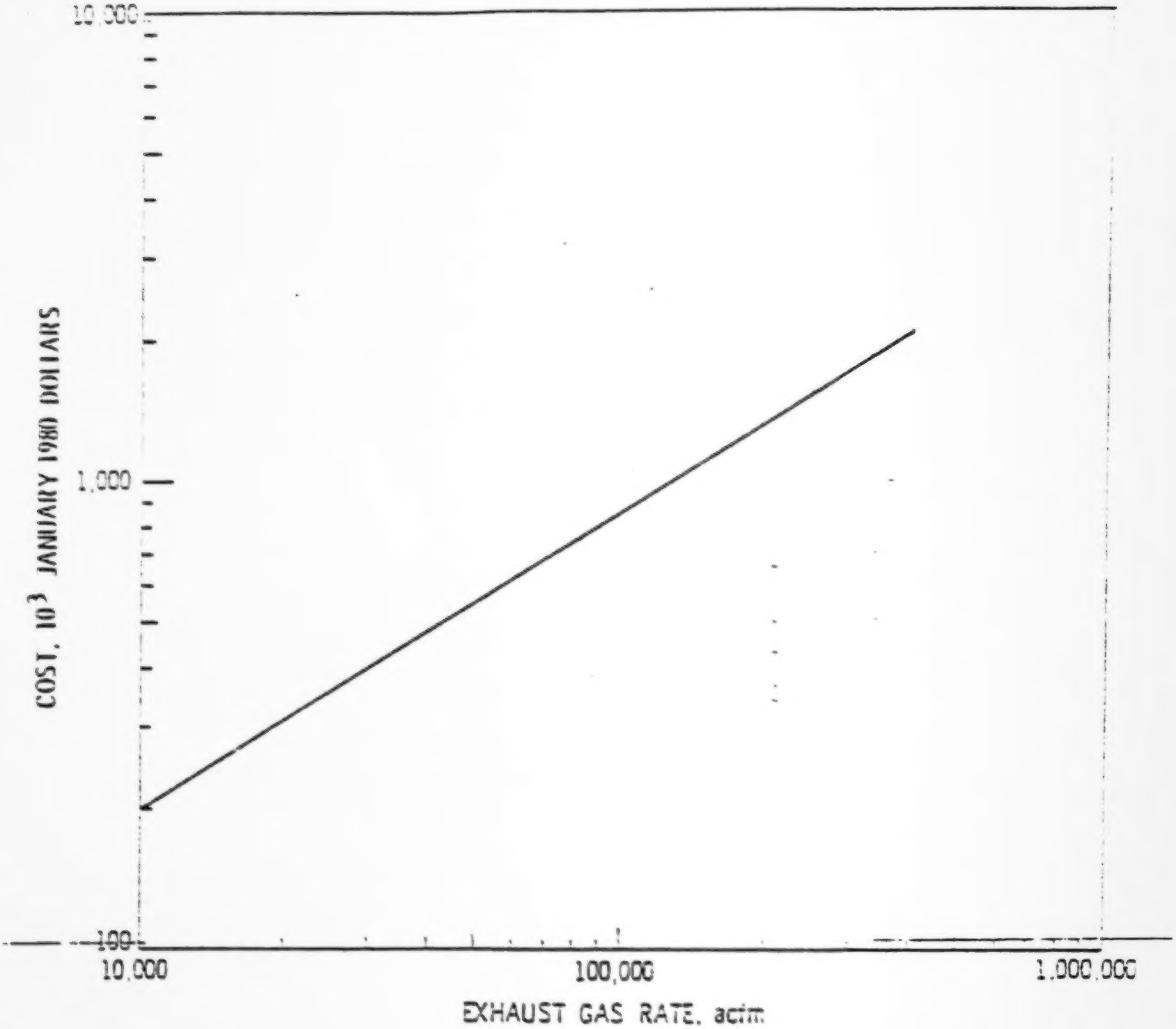
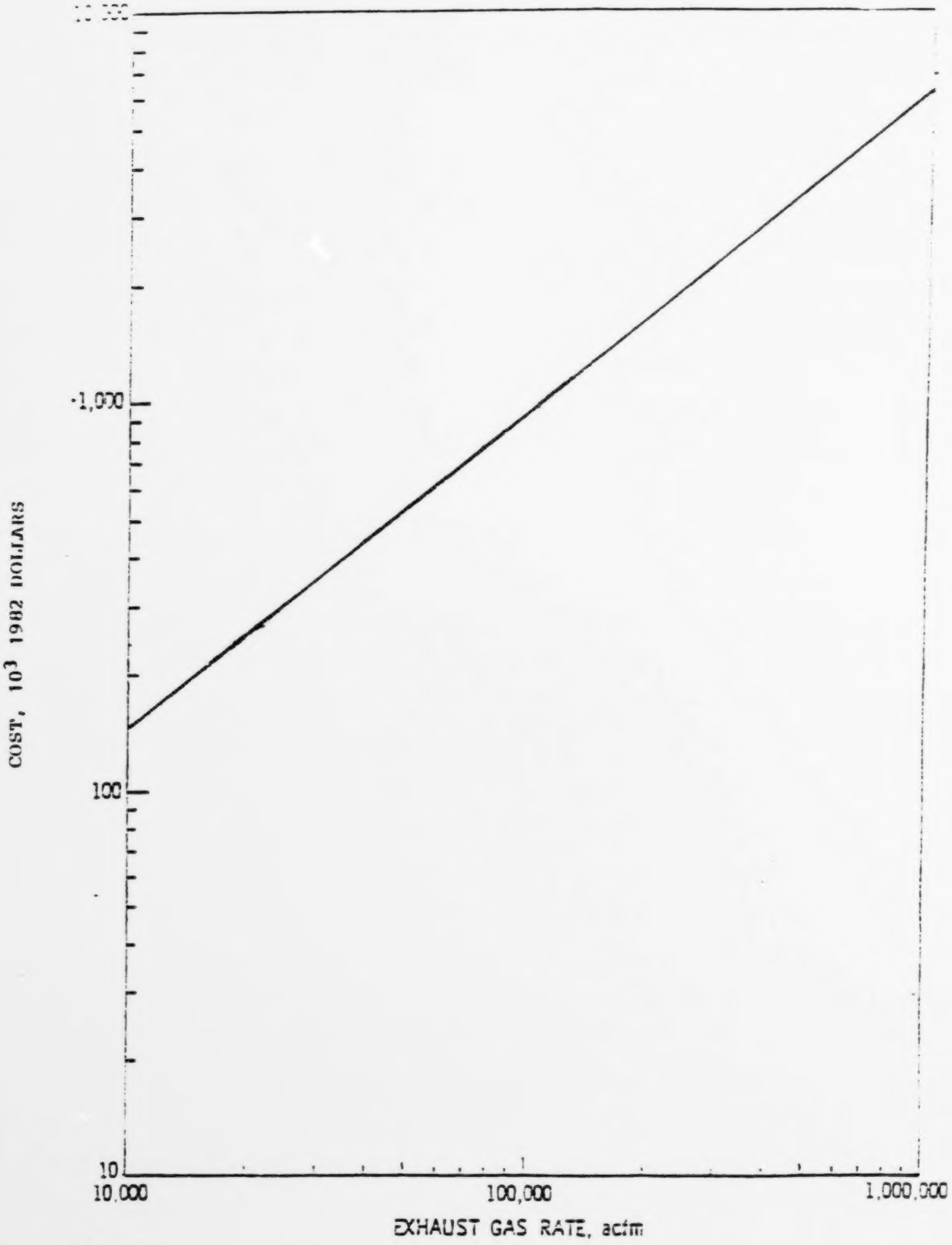


FIGURE 6.9

CAPITAL COSTS OF SCRUBBER/ABSORBER SYSTEM



impacts on boiler subsystems that can result from burning wastes containing these species are discussed in detail in Reference 19. There also may be increased boiler O/M costs as a result of increasing the number of burner guns and using more complex combustion control instrumentation. These costs are not expected to be significant, however.

Equipment required to meet adopted regulatory requirements will likely further increase the O/M costs associated with firing hazardous waste over those associated with firing conventional fuels. Air pollution control devices added to meet emission limitations will increase the O/M cost burden. Further costs will be incurred to maintain O_2 and/or CO monitoring, waste metering, and furnace temperature monitoring systems. O/M costs assocaited with waste metering are, however, expected to be insignificant. The costs of maintaining a furnace temperature monitoring system is difficult to estimate because of the uncertainty in predicting the frequency of thermocouple replacement.

This section presents O/M costs for the following of the aforementioned items:

- Waste pretreatment
- Boiler modification costs
- Air pollution control devices

Increased O/M costs associated with waste storage and handling other than pretreatment are provided by others. Boiler maintenance costs stemming from corrosion and fouling-related problems resulting from burning hazardous wastes are not given as there is not sufficient information available to develop them.

Pretreatment O/M Costs

The annualized O/M costs associated with the four pretreatment processes (blending, thermal treatment, water removal, and solids removal) for which capital costs were given in this section are presented here. Certain elements of these costs are generic to all four processes. These are listed in Table 6.7.

As shown in Table 6.7, the O/M costs include both direct and indirect components. The direct components include operating labor, maintenance, utilities, and residue disposal. Operating labor is taken at $9.75/manhour. Estimated labor requirements are one manhour per shift for solids removal, water removal, and blending. For thermal treatment, it is assumed that no operating labor is needed. Supervision is estimated at 15% of the total operating labor costs (Reference 20). Maintenance requirements are difficult to predict accurately for these types of operations. For such situations, maintenance is generally taken as 2-6% of the capital costs (Reference 21). Five percent was used in these estimates.

The only utilities required for these processes are electricity to drive the pumps and steam for the thermal pretreatment. Pump power consumption is estimated from the following equation:

TABLE 6.7

COMPONENTS OF ANNUALIZED COSTS

Direct Operating Costs	Cost Factor[a]
Operating labor	
Operator	$9.75/manhour
Supervisor	15% of operator
Maintenance	5% of capital costs
Utilities	
Electricity	$0.05/kwh
Steam	$6.00/1000 lbs.
Residue disposal	
Wastewater	$2.00/1,000 gal.
Sludges	$100/ton
Indirect Operating Costs	
Overhead	80% of operating labor and maintenance labor
Property tax	1% of capital costs
Insurance	1% of capital costs
Administration	2% of capital costs
Capital recovery cost	0.132 (using i = 10% and an equipment life of 15 years)

[a] All costs are in 1984 dollars.

$$\text{kwh} = \frac{0.746(\text{GPM})(\text{hd})(\text{SG})\text{H}}{3960n}$$

where: GPM = flow rate, U.S. gpm
hd = head of fluid, ft.
SG = specific gravity relative to water @ 60°F, 29.92 inches mercury
n = overall pump/motor efficiency = 40%
H = hours of operation

An electricity cost of $0.05 per kilowatt hour (Reference 22) was used in the power costs determination.

Steam is needed for the thermal pretreatment. An average cost of $6.00/1000 pounds of steam at 100 psi was used.

Total residue disposal costs include the costs for the sludge generated by the solids removal pretreatment and wastewater formed during the water removal pretreatment. Disposal of the sludge is by landfilling in a secure, hazardous waste landfill. The cost of this type disposal depends on location of the landfill. A representative cost is $100/ton (Reference 22). Water removed from wastes that are fired in boilers may be sent either to a municipal sewer (more typical of smaller facilities) or to the facilities' wastewater treatment plant. Municipal sewer charges are quite variable, but $2.00/1000 gallons is a reasonably representative charge. If the wastes are sent to an industrial wastewater treatment plant, the cost of disposing of the wastewater should be less. The $2.00/1000 gallon figure was assumed in calculating the annualized O/M costs. Residue disposal is increasingly the dominant O/M cost for solids removal pretreatment as the quantity of waste being treated increases. At 50 gal/hr , it is slightly over one-half the total O/M cost, while for a waste stream flow of 1000 gal/hr, it would be slightly over 90%.

The indirect operating costs include the costs of overhead, taxes, insurance, administration expenses, and capital charges. Taxes, insurance, and administration can collectively be estimated at 4% of the capital costs, while overhead charges can be considered at 80% of the labor charges for both O/M. The annualized capital charges reflect the costs associated with capital recovery over the depreciable life of the system and can be determined as follows:

$$\text{Capital Recovery Cost} = (\text{capital costs}) \times \frac{i(1+i)^n}{(1+i)^n-1}$$

where: i = annual interest rate
n = capital recovery period

For these estimates, a useful life of 15 years and an average annual interest rate of 10% were assumed.

Blending O/M Costs

Size and number of blending tanks will vary with waste fuel flow, and the time required to blend the mixture. This section is based on a three tank system: one filling, one blending, and one feeding the boiler. However, because one tank would be required as a dry tank, the costs are based on two storage tanks, agitators for all three tanks, and energy for all three tanks.

Waste materials would be pumped from storage into one tank, the volume transferred based on flow meters or tank level measurements. Several waste streams could flow to the blending tank at one time. As soon as the agitator propeller is covered, the agitator can be started. Required agitation time will vary widely, depending primarily on the viscosity of the waste material. Hazardous waste flowing to the tank should be shut off when the blending tank is filled. Filling may take one shift and blending may take one shift, after which the contents of the tank are fed to the boiler during one shift.

Operating and maintenance costs for this operation are shown in the following table.

Operating and Maintenance Cost - Blending

Tank Size (gal)	O&M Cost[a] ($/yr)
1,000	21,500
2,000	23,600
5,000	26,300
10,000	31,700
20,000	39,400

---

[a] One hour per shift (3 shifts/day) plus maintenance (5% of capital costs).

Thermal Treatment O/M Costs

Figure 6.10 presents the annualized thermal treatment O/M costs as a function of waste feed rate for the two categories of wastes for which capital costs were given earlier in this section:

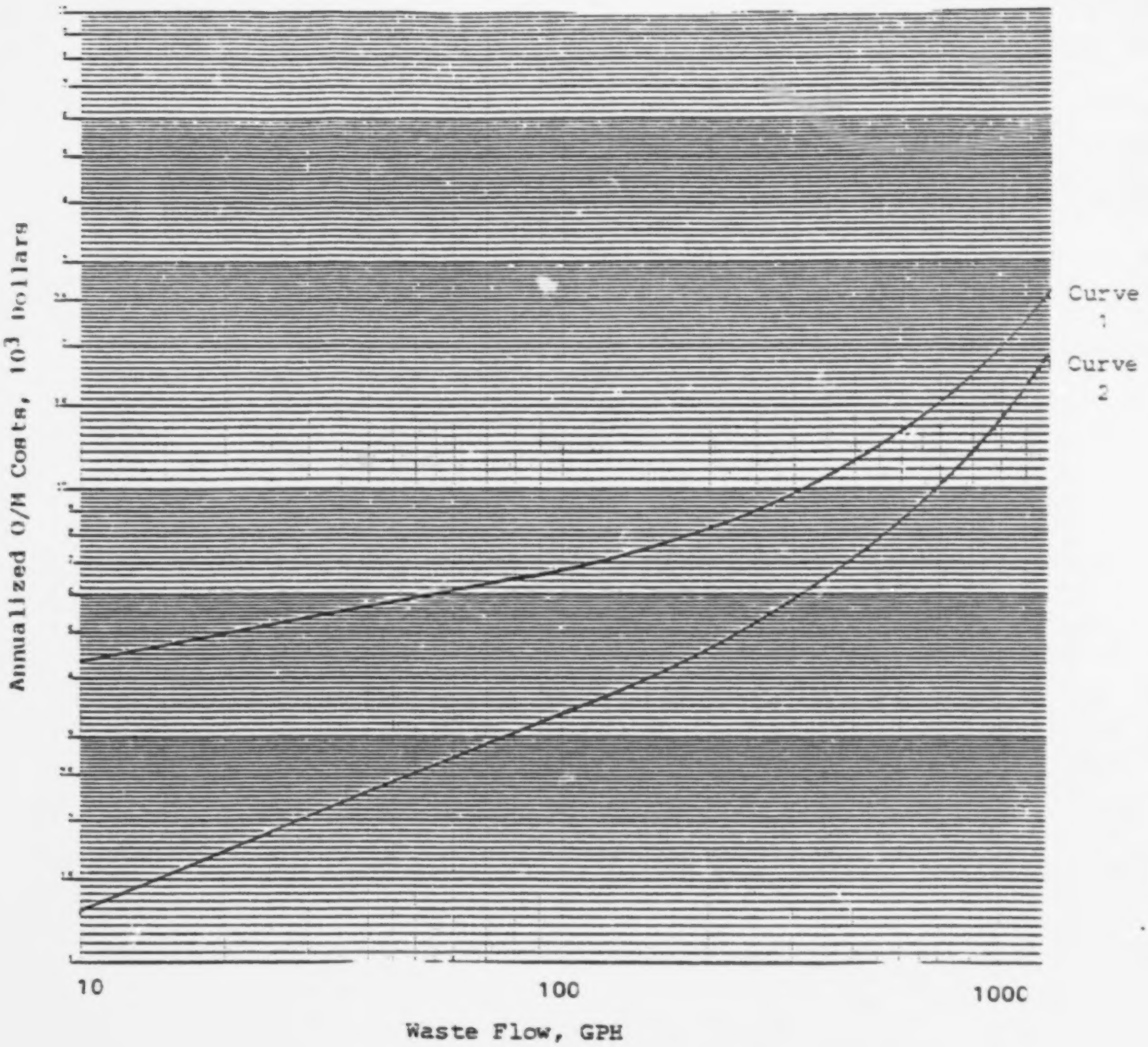
Curve 1 - Wastes with viscosities greater than 750 SSU but less than 10,000 SSU at ambient temperature.

Curve 2 - Wastes with viscosities greater than 10,000 SSU at ambient temperatures.

As with the capital costs, provisions for heating and insulating the storage tanks are not included in the O/M costs for wastes with viscosities greater than 10,000 SSU but are reported separately in the following table. Wastes with viscosities between 750 and 10,000 SSU at ambient temperature do not require storage tank insulating and heating.

FIGURE 6.10

ANNUALIZED O/M COSTS FOR THERMAL TREATMENT



Curve 1 - Pumpable at ambient temperatures but must be heated for good atomization

Curve 2 - Must be heated to keep pumpable and to obtain good atomization.

Operating and Maintenance Cost - Thermal Treatment

Tank Size (gal)	O&M Costs ($/yr)
500	470
1,000	890
2,000	1,710
5,000	2,190
10,000	3,900
20,000	5,380

Water and Solids Removal O/M Costs

The O/M costs for removing water from waste streams containing 10, 50, and 75% water are given in Figure 6.11. These costs assume that the water content is reduced to 5% before the waste is pumped to the boiler. The removed water is assumed to be sent either to the plant's wastewater treatment unit or to the sewer.

The solids removal costs are given in Figure 6.12. Disposal of the collected slurry is by far the dominant O/M cost as discussed above.

Boiler Modification O/M Costs

Burner Modification O/M Costs

The burner gun assembly and the associated controls to fire waste fuel should require little operator attention beyond that required for the boiler firing conventional fuels. Maintenance cost will be about 5% of capital cost, capital recovery 13.2%, and taxes and insurance 2%. Therefore, total annual O/M cost will be about 20.2% of the original burner gun assembly capital cost.

Processs Control Instrumentation

No additional operating labor will be required to operate the process control instrumentation. Maintenance and fixed costs are shown below.

Boiler Heat Input 10^6Btu/hr	Capital Cost $	O/M Cost $/yr
< 30	5,000	1,000
> 30	25,000	5,000

FIGURE 6.11

ANNUALIZED O/M COSTS FOR WATER REMOVAL

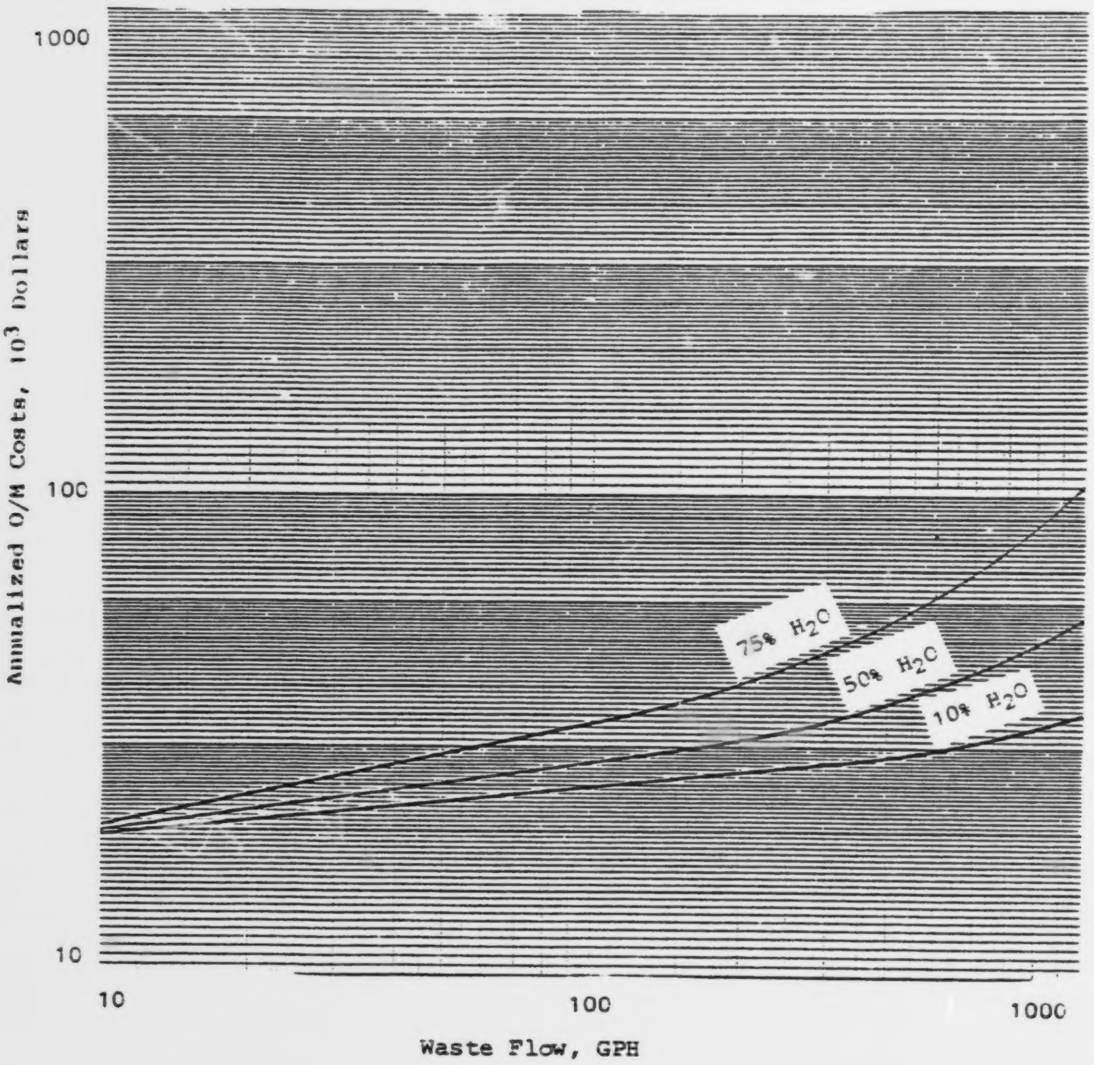
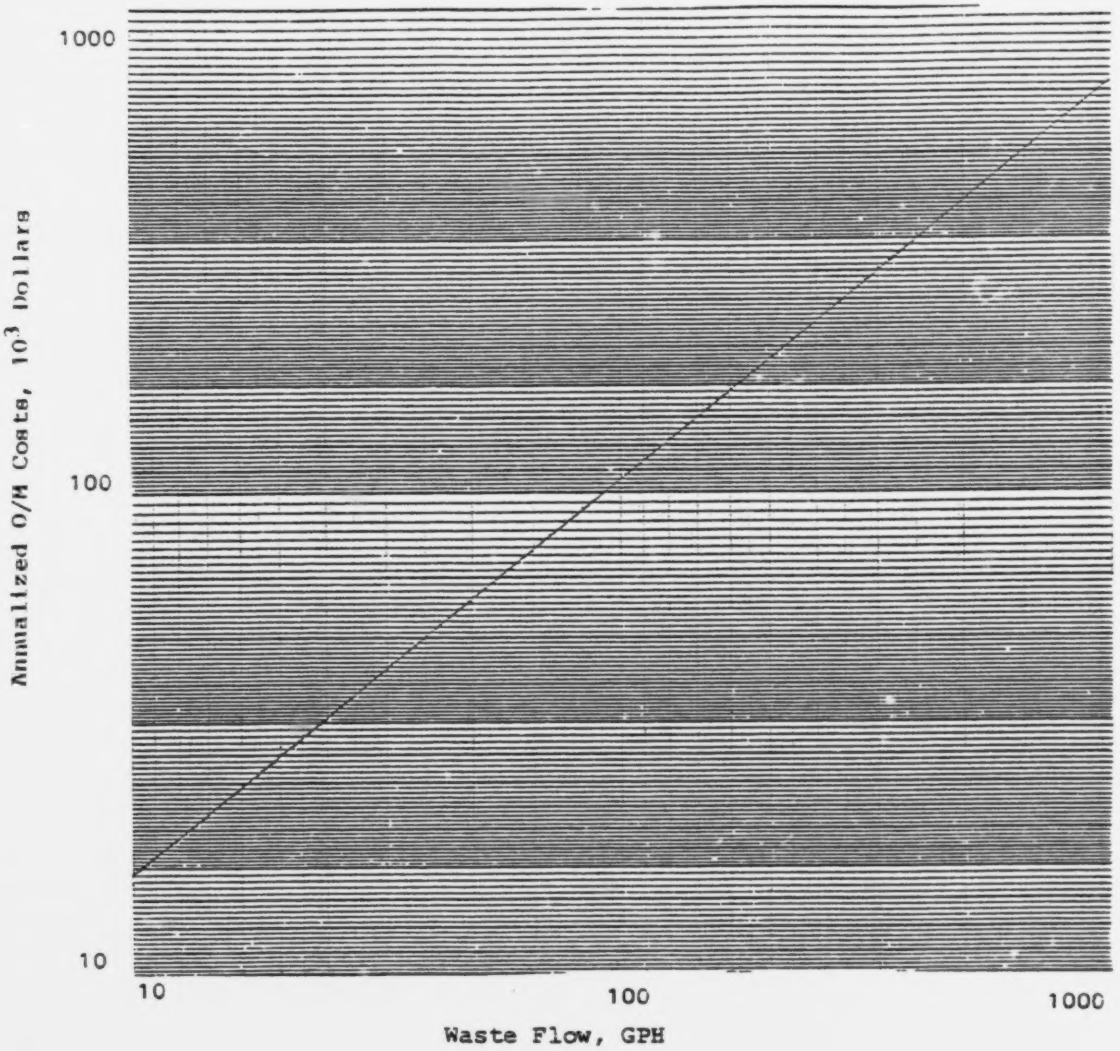


FIGURE 6.12

ANNUALIZED O/M COSTS FOR SOLIDS REMOVAL



Oxygen and Carbon Monoxide Monitoring O&M Costs

Annual operating costs for several continuous monitoring systems have been estimated for evaluating the economic impact of NSPS for industrial boilers (Reference 14). These costs should also be applicable to "clean" exhaust gas applications. An annual O/M cost of $18,500 in 1982 dollars was estimated for an oxygen monitoring system. Costs for a carbon monoxide system should be about the same. The major items included in this estimate are the maintenance and performance certification. One-half manhour per day was assumed to be required for the maintenance at a rate of $35.81/manhour, including supervisor and overhead. One certification test per year, costing $11,900 was assumed.

Requiring O_2 and CO monitors on industrial boilers burning hazardous waste could result in a fuel cost savings to the operators of these devices. This potential saving would result if the operators used the CO/O_2 monitors to maintain low excess air (LEA) combustion of the fuels. With LEA combustion, less fuel is required because less heat is lost out the stack with the combustion gases.

The magnitude of the potential fuel savings that can be obtained by LEA combustion must be determined individually for each boiler because it depends on many factors. The major factors influencing the potential savings include:

- Boiler type and condition
- Burner type and condition
- Combustion control type and condition
- Operating load level

The boiler type and condition have a large impact on the amount of fuel saving that may be achieved through LEA combustion. Some types have design characteristics that limit the range of LEA operation. Also, the flue gas exit temperature for one type boiler can be significantly different from those of another type. Since the fuel savings for a given excess air reduction is temperature dependent, boilers with higher exit flue gas temperatures should be capable of achieving a higher fuel savings per unit excess air potential of LEA. The condition of the boiler also impacts the fuel savings potential of the LEA. A boiler that has significant air in-leakage is more difficult to operate at low excess air levels because the air infiltration may distort the O_2 reading drastically.

The type and condition of the burner(s) installed in the boiler also greatly influence the fuel savings potential of LEA operation. A burner is designed to operate efficiently over a specific excess air range. If operated at an excess air range lower than the design level, proper mixing of the fuel and combustion air cannot be achieved. Poor air and fuel mixing would likely result in incomplete combustion of the fuel and higher fuel consumption. Gas burners generally operate at lower levels than coal burners. There is also a wide variation in the excess air level operations capability of burners for a given fuel. The condition of the burner also affects the potential fuel savings because the fuel flow through a dirty or damaged burner is difficult to control.

Another important factor determining the potential of LEA combustion and hence fuel savings is the type and condition of the combustion controls. Combustion controls vary widely in complexity from the simple single-point positioning units typically found on smaller units to the metering system of a complex, computerized process control system. Interfacing the CO/O_2 monitor to these systems has limitations that are unique to each type of control system. The level of LEA achievable is limited to how well the CO/O_2 monitoring is used by the control system. Also, the condition of control system mechanical components also impacts the fuel savings potential. Damper linkage may flex slightly, and bearings may wear over time. Even metering systems are susceptible to some shortcomings, since their flow transmitters are operated at temperatures and pressures that vary significantly from those at which the transmitters were initially calibrated.

More excess O_2 is needed at low loads because of poorer mixing of the fuel and air. Consequently, the operating load level also impacts the fuel savings of LEA combustion.

Because of the influence of the factors discussed above, a detailed breakdown of potential fuel savings by boiler type and fuel is deemed unjustified. For the purpose of determining the economic impact of requiring O_2/CO monitoring, a 2% savings is estimated as a typical average value. This estimate is based on discussions with combustion control equipment suppliers, information found in the literature, and data on oxygen levels and boiler exit flue gas temperatures. These savings are also based on an estimated 0.5% increase in combustion efficiency per 1% reduction in the O_2 level in the flue gas.

Not all boiler operators would receive the fuel saving estimated for LEA operation as a consequence of requiring O_2/CO monitoring. Some boilers are already equipped with O_2 trim or O_2/CO-trim. In fact, those boilers equipped with CO-trim systems may actually be required to operate at a higher LEA level than they are currently operating at, depending on the level of CO limits imposed, and thus would consume more fuel. Boilers with CO-trim systems typically are operated with a CO setpoint of from 200 to 400 ppm. A CO limit lower than this range would require that they operate at a higher LEA level than their current setpoint level. Also, some boilers are equipped with O_2-trim systems. Thus, estimating the fuel savings potential of requiring O_2/CO monitors on a particular population of boilers requires a knowledge of how many units in the population already are operating at LEA levels (i.e., how may are using O_2 or CO monitors to achieve LEA combustion.) Once the fraction of boilers currently employing LEA controls is determined, the potential fuel savings for the entire population may be estimated from the potential savings of a single unit.

The savings of a single boiler can be estimated by multiplying the total annual fuel cost by 0.02 or 0.04 depending on the type fuel burning device being considered. The annual fuel cost is estimated by multiplying the design heat input by the unit fuel cost presented in the preceeding paragraphs. For example, the maximum potential annual fuel savings of a 150×10^6 Btu/hr, residual oil-fired boiler would be:

$$.02 \times 150 \times 10^6 \text{ Btu/hr} \times 8760 \text{ hrs/yr} \times \$4.62/10^6 \text{ Btu} = \$121,400$$

This assumes that the boiler operates 24 hours per day, 365 days a year. This savings can be adjusted to match different assumptions regarding load factor.

A comprehensive survey of boilers was not conducted to determine the fraction of units already equipped with an LEA capacity.

Air Pollution Control Devices O/M Costs

The annualized O/M costs for electrostactic precipitators, baghouses, and combined venturi/gas absorption systems presented in Figures 6.13 through 6.15 are based on 8700 hr/yr operating time and the cost factors presented in Table 6.8. The annualized costs given in Figure 6.15 are for a combination venturi/gas absorption system. When no venturi is required, the O/M costs are approximately 85% of that given by Figure 6.15. The O/M costs include direct costs such as operating labor and materials, maintenance, replacement parts, utilities, and collected particulate disposal. Also included are indirect costs such as overhead, insurance, taxes, and capital recovery. Cost factors presented in Table 6.8 were estimated from information contained in Reference 16 and represent 1977 dollars. Methods for updating these costs to the year finally selected for indexing the economic impact analysis are detailed in Reference 16. The annualized O/M costs for the three types of control devices presented in Figures 6.13 through 6.15 are in 1980 dollars (Reference 23).

Estimated operating labor requirements for APCD systems (Reference 16) are 0.5 to 2 manhours per shift for electrostatic precipitators, 2 to 4 manhours per shift for baghouses, and 2 to 8 manhours per shift for wet scrubbing systems. The only utility requirement for baghouses and electrostatic precipitators is electricity. For baghouses, the power requirement is approximately 0.2 kwh per 1000 ft^2 for the reverse air fan motor. The power requirement of energizing the plates of a precipitator is approximately 1.5 watts per square foot of collection area (Reference 20). For the scrubber system, the ID fan is the major electricity consuming item. The following formula was used for calculating the electric requirement of the fan (Reference 16):

$$\text{kwh} = \frac{0.746(\text{CFM})(\Delta P)(\text{SG})H}{6356n}$$

where: kwh = kilowatt-hours
CFM = actual volumetric flow rate, acfm
ΔP = pressure loss, inches WG
n = efficiency, usually 60%
H = hours of operation

The scrubber also requires water which must be treated to remove solids and neutralize its collected HCl.

FIGURE 6.13

ANNUALIZED O/M COST OF ELECTROSTATIC PRECIPITATORS, CARBON STEEL CONSTRUCTION

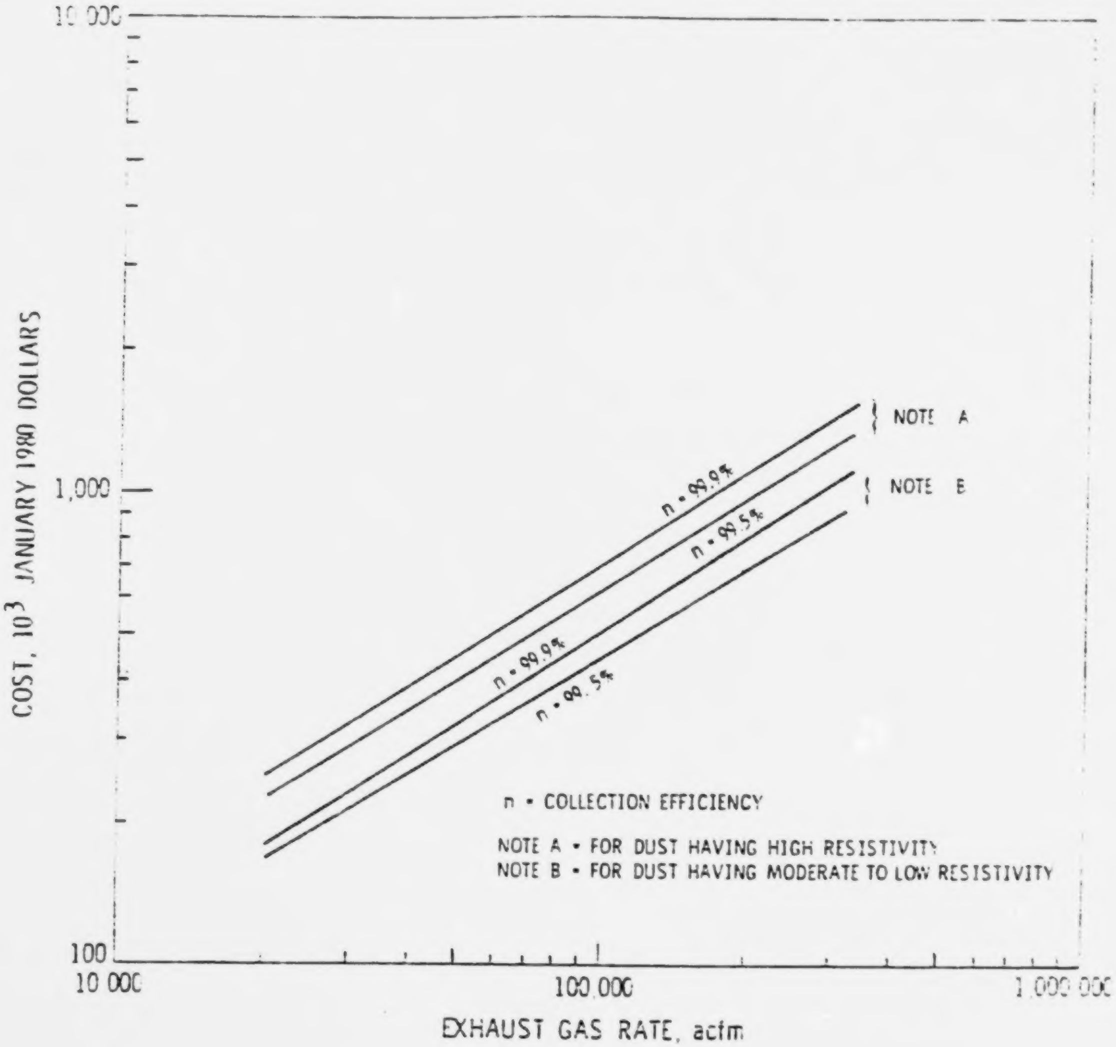


FIGURE 6.14

ANNUALIZED O/M COST OF REVERSE AIR FABRIC FILTERS, CARBON STEEL CONSTRUCTION

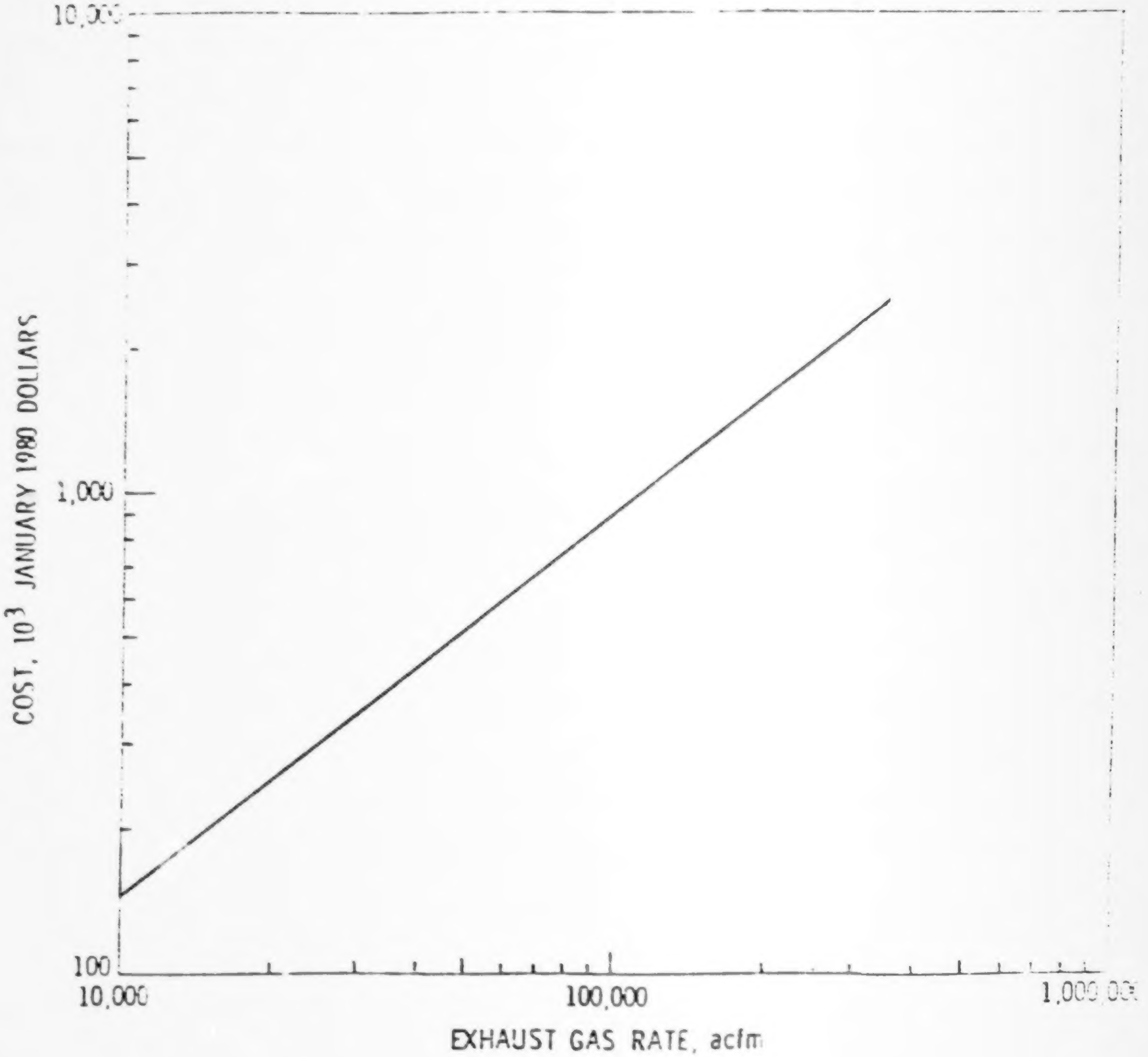


FIGURE 6.15

ANNUALIZED O/M COST OF A COMBINATION VENTURI/GAS ABSORPTION SYSTEM

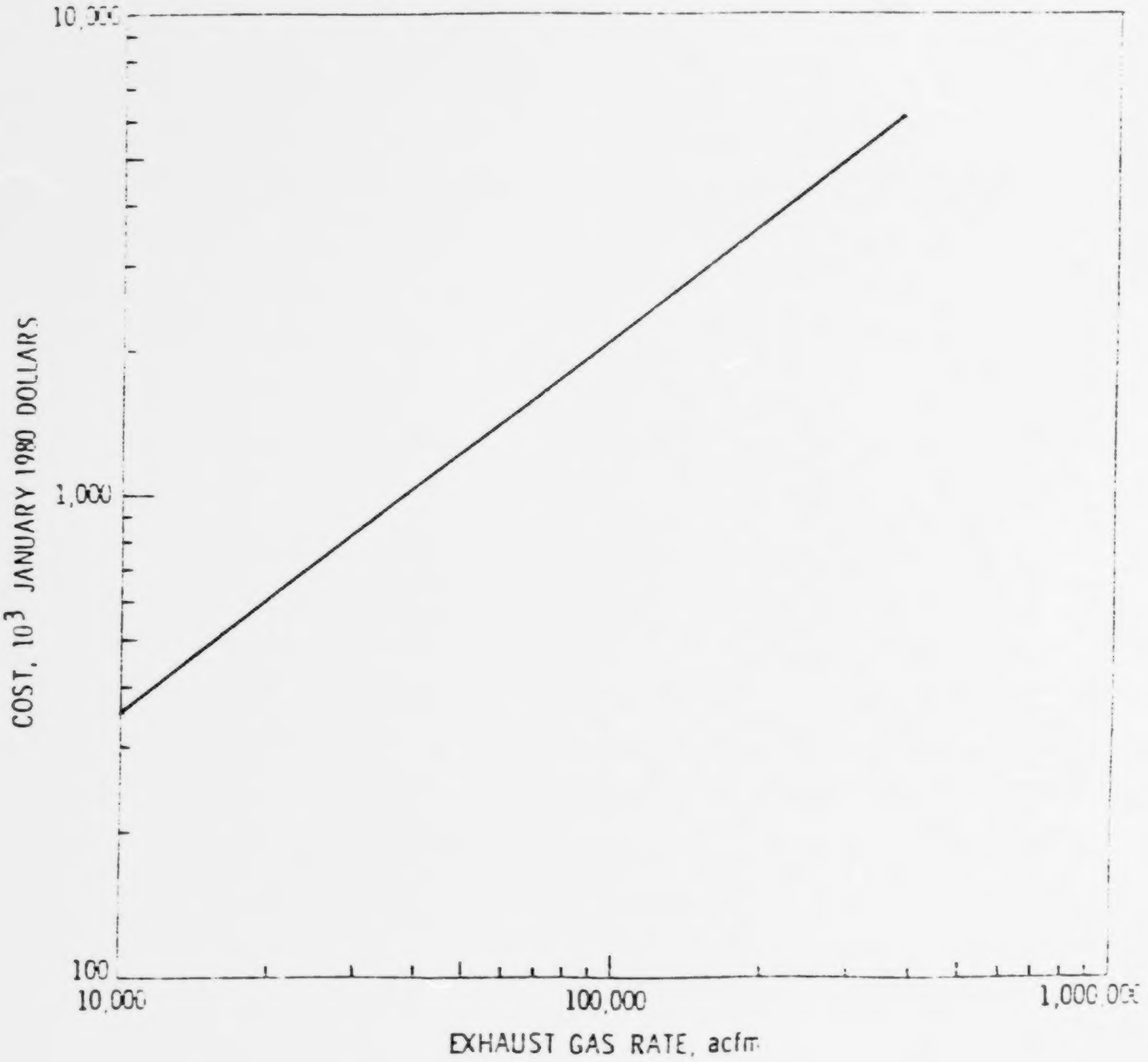


TABLE 6.8

COMPONENTS OF ANNUALIZED COSTS
(Reference 16)

Direct Operating Costs	Cost Factor[a]
Operating labor	
Operator	$7.87/manhour
Supervisor	15% of operator
Maintenance	
Labor	$8.66/manhour
Material	100 % of maintenance labor
Utilities	
Electricity	$0.0432 kwh
Water treatment and cooling water	$0.2500/1000 gallons
Waste disposal	$10.00/ton
Indirect Operating Costs	
Overhead	80% of operating labor and maintenance labor
Property tax	1% of capital costs
Insurance	1% of capital costs
Administration	2% of capital costs
Capital recovery cost	0.16275 (as an example of xf% and equipment life of xf years)

[a] All costs are in December 1977 dollars.

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